UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
BEFORE THE
BONNEVILLE POWER ADMINISTRATION

Fiscal Year 2016-2017 Proposed	**)**	**BPA Docket No. BP-16**
Power and Transmission Rate	**)**	
Adjustment Proceeding	**)**	

INITIAL BRIEF OF:
Public Power Council
Industrial Customers of Northwest Utilities
The City of Seattle
Northwest Requirements Utilities
as
JOINT PARTY 15

SUBJECT:
EASTERN INTERTIE RATES

May 1, 2015

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I. INTRODUCTION

In accordance with the applicable rules of procedure,[1] Public Power Council ("PPC"), Northwest Requirements Utilities ("NRU"), The City of Seattle, and Industrial Customers of Northwest Utilities ("ICNU"), jointly referred to as "Joint Party 15" or "JP15," file this Initial Brief to address the issues relating to the rate Bonneville Power Administration ("BPA") charges for transmission service over the Eastern Intertie segment. The record in this case does not support a decision to reverse BPA's long-standing practice of treating the Eastern Intertie as a separate segment and to roll in BPA's share of the Eastern Intertie costs into the Integrated Network. Therefore, the Administrator should reject the proposal to eliminate the Montana Intertie rate, and maintain the Eastern Intertie as a separate segment for ratesetting purposes.

All members of PPC and NRU are preference customers of BPA that purchase requirements power, or transmission services, or both, from BPA under the rates, terms, and conditions set out in BPA's rate schedules. The City of Seattle is a preference customer that purchases power and transmission services from BPA and is a member of PPC. ICNU is a non-profit organization whose members are industrial customers in the Northwest, many of which are end-use consumers of BPA power. Therefore, ICNU's members are directly affected by BPA's rates, terms, and conditions of service in a manner similar to BPA's preference customers.

A. The original purpose of the Eastern Intertie was to transmit remote generation under the Montana Intertie Agreement, and that remains its primary use today.

BPA "segments its transmission facilities based on the services those facilities provide."[2] Hence, "[s]egments are groups of transmission facilities that serve a particular function or

[1] § 1010.13 of the Bonneville Power Administration's Rules of Procedure Governing Rate Hearings (51 Fed. Reg. 7,611 (March 5, 1986)) and the Special Rules of Practice adopted for this proceeding (BP-16-HOO-02).
[2] Transmission Segmentation Study, BP-16-E-BPA-06, at 1.

provide a specific service and therefore are appropriate to group together for ratesetting purposes."[3] The facilities in BPA's Eastern Intertie segment include a double-circuit 500-kV transmission line between Townsend and Garrison in Montana, as well as the associated terminal equipment at the Garrison substation.[4] These facilities provide a transmission path from Montana to BPA's Integrated Network and were built pursuant to the Montana Intertie Agreement.[5]

BPA and a group of investor-owned utilities that owns coal-fired generating facilities located in southeastern Montana ("Colstrip facilities") are parties to the Montana Intertie Agreement.[6] With the expansion of the Colstrip facilities in the 1970s and 1980s, the Colstrip owners needed additional transmission capacity to carry electricity generated at the Colstrip facilities to the west, where their customers were located.[7] The Colstrip owners took various steps to obtain the necessary capacity, including requesting that BPA construct 500 kV transmission lines west from Townsend to Garrison in Montana.[8] BPA agreed and ultimately completed the Eastern Intertie, [9] which, since energization, has been used primarily for transmission of Colstrip generation.[10] This service is provided to only five parties.[11]

The Montana Intertie Agreement provides for the construction and operation of the Eastern Intertie, cost allocation among the parties to the agreement, and transmission service by

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[3] *Id*.
[4] *Id*. at 6.
[5] *Id*.
[6] *See id.*; Administrator's Final Record of Decision, 2014 Wholesale Power and Transmission Rate Adjustment Proceeding ("BP-14 ROD"), BP-14-A-03, at 176.
[7] *Pacific Power & Light Co. v. Montana Dept. of Revenue*, 773 P.2d 1176, 1179 (Mont. 1989), *cert. denied*, 493 U.S. 1050 (1990).
[8] *Id.*; *Portland General Elec. Co. v. Montana Dept. of Revenue*, 773 P.2d 1189, 1192 (Mont. 1989), *cert. denied*, 493 U.S. 1049 (1990).
[9] *Pacific Power & Light Co.*, 773 P.2d at 1179.
[10] Tenney *et al.*, BP-16-E-BPA-16, at 24 (citations omitted).
[11] *Id.* (citations omitted).

BPA over the Eastern Intertie. Specifically, the costs associated with building and maintaining the Eastern Intertie are recovered from the parties to the agreement through the Townsend-Garrison transmission rate[12] – identified as the "TGT rate" or "TGT-16 rate" in this proceeding. In addition, BPA acquired ownership of 200 MW of capacity on the Eastern Intertie and offers transmission service to its customers at the Montana Intertie rate – identified as the "IM rate" or "IM-16 rate" in this proceeding.[13] "Only 16 MW of BPA's Eastern Intertie westbound capacity has been sold on a long-term basis, and that sale was for transmission of Colstrip generation."[14]

II. ARGUMENT

A. The record in this case does not support a decision to reverse BPA's long-standing practice of treating the Eastern Intertie as a separate segment and to roll BPA's share of the Eastern Intertie costs into the Integrated Network.

Consistent with the purpose for which the Eastern Intertie facilities were constructed and have been used, BPA has always separately segmented the Eastern Intertie. BPA Staff proposes to retain the current segmentation and rate design in FY2016-17 because "[t]he status quo is consistent with established practice regarding the Eastern Intertie,"[15] and all interested rate case parties except for one support BPA Staff's initial proposal.[16] Renewable Northwest ("RN") proposes that BPA eliminate the IM rate, charge the Network rates for transmission service from the Eastern Intertie to any point on the BPA's Integrated Network, and include or "roll in"

[12] Transmission Segmentation Study, BP-16-E-BPA-06, at 6.
[13] Tenney *et al.*, BP-16-E-BPA-16, at 24; 2016 Transmission, Ancillary, and Control Area Service Rate Schedules, BP-16-E-BPA-10, at 23.
[14] Tenney *et al.*, BP-16-E-BPA-16, at 24 (citations omitted).
[15] *Id*. at 24. Notably, BPA Staff filed rebuttal testimony "to address the testimony of Renewable Northwest (RN)." Metcalf *et al.*, BP-16-E-BPA-32, at 1. Although BPA Staff noted in its testimony that RN's testimony should be "strongly considered," *id.*, upon further inquiry, it clarified that it did not repudiate or change its initial proposal to retain the status quo, did not assert that "'the Administrator should favor a proposal with regard to Eastern Intertie rates that differs from the initial proposal,'" and did not "'recommend that the Administrator should more favorably consider Renewable Northwest's proposals than any other proposals regarding the Eastern Intertie.'" Baker *et al.*, BP-16-E-JP15-01, at 4 (internal citations omitted).
[16] *See generally* Baker *et al.*, BP-16-E-JP07-03; Baker *et al.*, BP-16-E-JP15-01; Arthur, BP-16-MS-02; Arthur, BP-16-MS-03; Saleba, BP-16-E-WG-03; Brown, BP-16-E-JP12-01;Yourkowski, BP-16-RN-01.

BPA's share of the Eastern Intertie costs into the Integrated Network and the Network rates.[17] Similar proposals were made in the last two rate cases, but rejected each time. In the BP-12 rate case, the Administrator noted that "[c]hanging the allocation of costs of transmission facilities previously classified as a separate segment in rates is a segmentation decision that must be supported by an appropriate rate case record."[18] Likewise, a different Administrator in the BP-14 rate case noted that "the separate segmentation of BPA's Eastern Intertie capacity … should be changed only with good reason."[19]

The Administrators were correct in their observations. Under the Administrative Procedures Act, any change in policy or practice by BPA must be cogently explained and supported by evidence in the record. In other words, "the agency must examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made."[20] An agency cannot act on pure speculation or contrary to the evidence in the record,[21] and, if changing its course, the agency "is obligated to supply a reasoned analysis for the change beyond that which may be required when an agency does not act in the first instance."[22] When BPA has arbitrarily departed from its long-standing practices in the past, the Court has applied this standard to set aside BPA's actions.

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[17] Yourkowski, BP-16-RN-01, at 3. While RN proposes to eliminate the IM rate, it does not expressly propose to eliminate the Eastern Intertie segment. RN does not explain what would happen to the Eastern Intertie segment if the IM rate was eliminated. Presumably, there would be no practical purpose for the segment to remain separate. Therefore, we treat the proposal to eliminate the IM rate as functionally equivalent to the proposal to eliminate the Eastern Intertie segment.

[18] Administrator's Final Record of Decision, 2012 Wholesale Power and Transmission Rate Adjustment Proceeding ("BP-12 ROD"), BP-12-A-02, at 480.

[19] BP-14 ROD, BP-14-A-03, at 176 (citation omitted).

[20] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (internal citation omitted).

[21] *Arizona Cattle Growers' Ass'n v. Salazar*, 606 F.3d 1160, 1164 (9th Cir. 2010).

[22] *Motor Vehicle Mfrs. Ass'n of U.S., Inc.*, 463 U.S. at 42; *see also Northwest Environmental Defense Center v. Bonneville Power Admin.*, 477 F.3d 668, 687-688 (9th Cir. 2007).

No material fact has changed since the last two Administrators rejected proposals to roll BPA's share of the costs of the Eastern Intertie into the Integrated Network.[23] The Eastern Intertie continues to be used solely to import generation from Montana to the Pacific Northwest. The record in this proceeding is devoid of reliable evidence that there has been, or will be in FY 2016-17, a change in the usage, function or voltage of the Eastern Intertie. There are no new users or new uses of the facilities, and none are reasonably expected in the FY 2016-17 rate period or documented in the record. There are no new "benefits" to BPA's Network customers, notwithstanding assumptions and speculations that underlie the arguments in favor of rolling in the Eastern Intertie. In fact, BPA Staff explained that it was proposing to retain the status quo in its initial proposal, "[b]ecause adequate justification has not been provided for roll-in of BPA's Eastern Intertie capacity."[24] Neither the record nor the facts, therefore, would support a decision to reverse BPA's long-standing practice of treating the Eastern Intertie as a separate transmission segment.

B. BPA should reject RN's proposal to eliminate the IM rate.

RN advances several reasons to support its proposal to eliminate the IM rate, most of which were previously rejected. RN argues that segmenting the Eastern Intertie separately from BPA's Network is based on outdated reasoning, and that eliminating the IM rate would (1) encourage the development of new wind resources in Montana;[25] (2) facilitate Montana's compliance with the Environmental Protection Agency's ("EPA") Clean Power Plan;[26] and (3) "has the potential to make all parties better off than the status quo."[27]

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[23] Baker *et al.*, BP-16-E-JP07-03, at 3.
[24] Tenney *et al.*, BP-16-E-BPA-16, at 24.
[25] Yourkowski, BP-16-E-RN-01, at 1.
[26] *Id*.
[27] *Id*.

1. The Eastern Intertie continues to be used for its intended purpose.

RN acknowledges that the Eastern Intertie was built for BPA to provide transmission service for Colstrip generation to BPA's integrated Network, but argues that "much has changed since the early 1980's."[28] While some things may have changed, the use and the underlying purpose of the Eastern Intertie – to import remote generation to the Pacific Northwest – have not. The evidence in the record is undisputed – since energization, the Eastern Intertie has been used for transmission of Colstrip generation,[29] only 16 MW of BPA's westbound capacity over the Eastern Intertie have been sold and that was for transmission of Colstrip generation,[30] and "no customer has reserved transmission service over BPA's Eastern Intertie capacity since 2006."[31] Current use of the Eastern Intertie does not include long-term transmission of any generation other than Colstrip generation. There are no requests in BPA's Eastern Intertie transmission queue today, and RN does not assert otherwise;[32] therefore, there is no demonstrable incremental demand for the use of the Eastern Intertie transmission services. Based on these very facts, the Administrator in BP-14 concluded that "the Eastern Intertie should remain a separate segment,"[33] and this Administrator should conclude the same.

2. RN fails to demonstrate that charging the IM rate impedes the development of wind generation in Montana by limiting its competitiveness.

Currently, transmission customers seeking to deliver energy west from eastern Montana would pay the IM rate from Townsend, where the Eastern Intertie begins, to Garrison, where the

[28] *Id*. at 5.
[29] Tenney *et al.*, BP-16-E-BPA-16, at 24 (citation omitted).
[30] *Id*.
[31] Metcalf *et al.*, BP-16-E-BPA-32, at 7.
[32] Baker *et al*., BP-16-E-JP07-03, at 3.
[33] BP-14 ROD, BP-14-A-03, at 176 (citation omitted).

Eastern Intertie connects to BPA's Integrated Network.[34] From Garrison, they would pay a BPA Network rate for service on the Integrated Network.[35] RN characterizes this combination of the IM rate and a BPA Network rate for customers that would take service from Townsend to any point west of Garrison as a "rate pancake" that decreases the competitiveness of Montana's wind resources.[36] Elimination of the IM rate, according to RN, would therefore encourage the development of new wind generation.[37] In fact, RN goes even further, testifying that "the presence of the IM rate has undermined the ability of Montana wind developers to market [wind] and has left wind development in Montana stalled for years."[38]

Yet, RN does not offer credible evidence to support its claims that it is the IM rate that has caused the failure of wind development in Montana.[39] The record contains no testimony, analysis, or studies suggesting that wind developers would fill BPA's queue with requests for transmission service over the Eastern Intertie if the IM rate were eliminated, or that the existence of the IM rate is what is stopping wind development plans. To the contrary, Joint Party 07 and JP15 have submitted well-supported economic analysis that the IM rate is not a material factor in Montana wind resource development.

"When considering economic issues, it is essential to consider not only whether an effect might exist, but also whether it would have an actual and substantial impact in practice."[40] At the outset, developers considering whether to invest in wind projects are likely to consider the levelized cost of wind generation.[41] As part of its 2014 Annual Energy Outlook, the Energy

[34] BP-12 ROD, BP-12-A-02, at 476.
[35] *Id*. (citation omitted).
[36] Yourkowski, BP-16-E-RN-01, at 2.
[37] *Id*. at 2, 4-7.
[38] *Id*. at 7.
[39] Baker *et al.*, BP-16-E-JP07-03, at 4.
[40] *Id*. at 5.
[41] *Id*. at 6.

Information Administration conducted an analysis of the levelized cost and variance in cost of new wind resources. For resources entering service in 2019, the levelized cost of wind generation nationally ranges from $71/MWh (minimum) to $80/MWh (average) to $90/MWh (maximum) in 2012 dollars.[42] RN has calculated that the IM-16 rate would add $2/MWh to the costs of a hypothetical wind plant in Montana, and "thus, materially reduces the competitiveness of Montana wind."[43] The $2/MWh cost impact of IM-16 rate, however, "is completely dwarfed in comparison to the variability of the levelized costs of specific wind resources," and is not likely to materially affect a developer's decision to invest in Eastern Montana wind.[44] This is the reason the Administrator rejected RN's argument in the BP-14 case, stating: "[g]iven the high cost of wind generation, the cost of transmission at the IM rate is only a small component of the delivered cost of eastern Montana wind generation."[45]

In addition, developers considering investing in wind projects within the BPA network are likely to compare the levelized costs of Montana and Columbia Gorge wind projects, including the costs of transmitting generation to the BPA Network. A recent assessment by the Northwest Power and Conservation Council – cited by RN in its testimony – makes just such a comparison and shows that a wind resource located in the Columbia Basin costs $111/MWh, while the hypothetical Montana wind resources delivered to the BPA system under two transmission assumptions cost $106/MWh and $103/MWh, respectively.[46] RN's own evidence, therefore, demonstrates that Montana wind is not only competitive, but may actually cost less

[42] *Id*. (footnote omitted).
[43] Yourkowski, BP-16-E-RN-01, at 6.
[44] Baker *et al.*, BP-16-E-JP07-03, at 6.
[45] BP-14 ROD, BP-14-A-03, at 177-78.
[46] Baker *et al.*, BP-16-E-JP07-03, at 7.

than the Columbia Gorge wind resources even with the IM rate.[47] This evidence alone is sufficient to establish that rolling in BPA's Eastern Intertie capacity would not encourage development of wind generation in Montana.

Viewed in the context of much more significant factors that drive the economics of wind development, RN's assertion that the IM rate is responsible for the failure of wind development in Montana is untenable. Specifically, "development of wind resources is heavily influenced by demand (particularly demand created by renewable portfolio standard or other mechanisms) and by government payments for production."[48] "The availability of the Production Tax Credit has historically been recognized by many sources as an overwhelming factor in the decision to develop wind resources."[49] At $22/MWh, this credit is so much larger than the $2/MWh cost impact of the IM rate, that it dwarfs any effects of the IM rate on the potential development of a Montana wind resource.[50]

Moreover, other hurdles unrelated to payment of the IM rate bear heavily on Montana wind development. As BPA Staff points out, "[e]ven with elimination of the IM rate, wind generation in Montana would face a number of transmission hurdles to get to points of delivery on BPA's Network."[51] BPA Staff describes those hurdles in its rebuttal testimony:

> Currently, the only way to get to Townsend is through Broadview. Therefore, the customer would need to obtain transmission to Broadview, probably over NorthWestern Energy's (NWE) system. Next, the customer would need to acquire transmission service from Broadview to Townsend. If the customer can obtain that service from NWE, we understand that there would be no additional charge, because NWE has rolled its Montana Intertie rights into its Network rates. However, NWE currently posts only 49 MW of Available Transfer Capability (ATC) to BPA at Townsend. To obtain any additional capacity, it would appear that the customer would need to purchase

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[47] *Id*. at 7.
[48] *Id*. at 8.
[49] *Id*.
[50] *Id*.
[51] Metcalf *et al.*, BP-16-E-BPA-32, at 7.

> transmission from one of the other Colstrip Transmission System owners and pay an additional transmission charge, unless the customer sought to have NWE add capacity on its system in accordance with NWE's Open Access Transmission Tariff. Finally, the customer would need to acquire transmission service over BPA's Network, including over the West of Garrison and West of Hatwai flowgates. Currently, requests in BPA's transmission queue that would use those flowgates exceed the ATC.[52]

Given the magnitude of transmission challenges facing prospective developers of wind resources in Montana, eliminating the IM rate is unlikely to be a substantial factor in encouraging new wind development in Montana. For the same reason, BPA Staff is appropriately cautious about assuming any benefits would accrue to BPA from any additional transmission service that might be sold over the Eastern Intertie.[53]

Finally, RN's argument that the IM rate "discourages the use"[54] of BPA's share of Eastern Intertie capacity by wind or other resources is refuted by the fact that the Colstrip owners have paid the TGT rate under the Montana Intertie Agreement, in addition to paying BPA's Network rate for transmission of Colstrip generation to loads.[55] As the Administrator noted in the BP-14 ROD, this fact "is inconsistent with [RN's] assertion that the IM rate would discourage Montana wind or other Montana generation."[56] As in BP-12 and BP-14, there is no evidence in the record of this case that the IM rate has undermined the development of wind generation in Montana. This Administrator should therefore conclude, as past Administrators have, that "roll-in of BPA's Eastern Intertie capacity would not significantly encourage development of renewable generation in the Pacific Northwest, and maintaining the IM rate would not discourage the development of Montana renewable generation or other generation."[57]

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[52] *Id*. at 7-8.
[53] Baker *et al*., BP-16-E-JP15-01, at 11 (citing Metcalf *et. al*., BP-16-E-BPA-32, at 7-8).
[54] Yourkowski, BP-16-E-RN-01, at 5.
[55] BPA-14 ROD, BP-14-A-03, at 178.
[56] *Id*.
[57] *Id*. (italics removed).

3. The IM rate does not impede Montana's compliance with EPA's Clean Power Plan; moreover, this argument is far too speculative to be considered by the Administrator.

The only new argument RN advances in this case is that eliminating the IM rate will facilitate the state of Montana's compliance with the EPA's Clean Power Plan.[58] The Administrator should not credit such a speculative argument. First, the Clean Power Plan has not been adopted,[59] and RN admits that the EPA has only "proposed" it and "is in the process of finalizing the proposed rule."[60] Second, while the *proposed* Clean Power Plan contains certain requirements for Montana's reduction of its carbon dioxide emissions, "it is not clear what, if anything, will finally be adopted by EPA and, if adopted, actually enforced."[61] The United States Congress has been holding hearings on the proposed Clean Power Plan and exploring the concerns that various industry groups have raised about the plan's potential impacts on reliability and costs, among others things.[62] "Given the uncertainty of the content and viability of the plan, there is … [only] … speculation to support the consideration of the plan in BPA's rates decisions for the FY2016-17 rate period."[63]

Third, the proposed Clean Power Plan imposes no obligations on BPA, and BPA is not obligated in any way to facilitate Montana's obligations under the Clean Power Plan, whatever those obligations might end up being. BPA's statutes impose limitations on its actions and would guide a court's evaluation of the lawfulness of BPA's actions in this proceeding. In establishing rates for the sale and disposition of electric energy and capacity and for the transmission of non-federal power, BPA must ensure that the rates are established in accordance

[58] Yourkowski, BP-16-E-RN-01, at 7.
[59] Baker *et al.*, BP-16-E-JP07-03, at 9.
[60] Yourkowski, BP-16-E-RN-01, at 7.
[61] Baker *et al.*, BP-16-E-JP07-03, at 10.
[62] *Id*.
[63] *Id*.

with the rate-setting directives in its enabling statutes.[64] RN's argument that "BPA should level the playing field for Montana resources and help position the State of Montana to comply with the federal government's Clean Power Plan"[65] not only has no support in BPA's statutes, but it also advocates for considerations that are far beyond those that BPA can take into account when setting rates.

4. Rolling in the Eastern Intertie would transfer costs and risks to the Network customers in violation of cost causation.

Under the principle of cost causation, the entities that create the costs bear the responsibility to pay those costs or, alternatively, the costs of an identifiable segment of transmission facilities that benefit only a discrete class of customers should be borne by that class of customers. As BPA Staff explained, because the "intertie segments are used to provide distinct services that are not used by all of BPA's customers," adopting separate intertie rates "strikes an appropriate balance between the widest diversified use requirement and cost causation."[66]

Rolling in the Eastern Intertie would expose BPA's Network customers to a variety of costs they did not cause, which violates the principle of cost causation. "The Eastern Intertie was purpose-built for customers wishing to import energy into the Northwest," and that continues to be its dominant use.[67] The addition of wind generation to the coal generation transmitted to the Northwest using the Eastern Intertie facilities does not change the nature of the service provided and does not change the fact that the users of the facilities are a small subset of BPA's customers. The costs of the Eastern Intertie should follow the benefits which currently, and for

[64] 16 U.S.C. § 839e(a).
[65] Yourkowski, BP-16-E-RN-01, at 9.
[66] Tenney *et al.*, BP-16-E-BPA-16, at 23.
[67] Baker *et al.*, BP-16-E-JP07-03, at 13-14.

the foreseeable future, flow exclusively to the power generators that use those facilities. "With the proposed IM rate, new potential users of the Eastern Intertie would make the same use of the facility and would contribute to payment of the original investment through payment of the IM rate."[68] Therefore, BPA's initial proposal to "retain the status quo,"[69] is consistent with the nature and current function of the Eastern Intertie.

The fact that rolling in Eastern Intertie costs that are currently collected by the IM rate would have a "small"[70] impact on Network rates does not justify ignoring the principle of cost causation. Whether a rate impact is "small" is a matter of perspective. Moreover, while the rate impact for the first rate period, taken alone, may not be substantial, the cumulative rate impact year after year, with the additional burden of capital improvement costs, would not be "small." Thus, the size of the rate impact to Network customers during one rate period does not justify BPA departing from a bedrock ratemaking principle like cost causation.

RN argues that "all parties are more likely to see increased revenue and/or decreased transmission costs under [its] proposal than under the status quo."[71] To the contrary, evidence in the record indicates that rolling in the Eastern Intertie is likely to impose significant costs and risks on BPA's Network customers, which are largely ignored by BPA Staff in its rebuttal testimony.

a. BPA risks under-recovering its current costs.

Under RN's proposal, "BPA would recover less costs than under the Network charge," thereby failing to fully recover the costs of providing transmission service over the Eastern

[68] Baker *et al.*, BP-16-E-JP07-03, at 14.
[69] Tenney *et al.*, BP-16-E-BPA-16, at 24.
[70] *Id*. at 22.
[71] Yourkowski, BP-16-E-RN-01, at 12.

Intertie.[72] This is so because RN proposes to credit a portion ($0.598/kW-mo) of the proposed Network rate ($1.487/kW-mo PTP rate) as an offset to the TGT rate that BPA charges the parties to the Montana Intertie Agreement.[73] Under RN's proposal, BPA would recover $0.889/kW-mo from transmission customers taking service from Townsend, Montana to any point on the BPA's network, which is less than BPA would recover from other customers taking transmission on the Network.[74] Therefore, adopting RN's proposal would inappropriately cause BPA to under-recover the cost of Network facilities from some of the Network customers.[75]

b. BPA and its Network customers face substantial risk of new expansion costs.

As the Administrator noted in the BP-14 ROD, "[t]here is a risk of additional costs from roll-in of BPA's Eastern Intertie capacity,"[76] and that risk is unrefuted in this case. BPA has 184 MW of available transmission capability for incremental use on the Eastern Intertie, but "there could be several thousand megawatts of new Montana wind generation accessing BPA's transmission system, which could result in significant cost impacts."[77] Over the long term, Network customers could bear the costs incurred to expand the Network and Eastern Intertie facilities to accommodate additional wind generation east of Garrison, Montana. "In setting rates, BPA has an obligation to look beyond the current costs and upcoming rate period and consider the long-term impacts of its decisions."[78]

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[72] Baker *et al.*, BP-16-E-JP07-03, at 11.
[73] *Id.* at 11-12.
[74] *Id*. at 12; Errata to BP-16-E-JP07-03, BP-16-E-JP07-03-E01.
[75] 16 U.S.C. § 838g requires Administrator to establish rates with "regard to the recovery … of the cost of producing and transmitting such electric power…"
[76] BP-14 ROD, BP-14-A-03, at 180.
[77] *Id*. at 179 (citations omitted); *see also* Metcalf *et al.*, BP-16-E-BPA-32, at 10 ("The feasible potential for development of the Montana wind resource is in excess of 9,000 MW.").
[78] Baker *et al.*, BP-16-E-JP15-01, at 6.

Under BPA's current Network Open Season (NOS) process, the costs of potential expansion projects could become the responsibility of the Network customers, creating a mechanism for the wind generators to transfer those costs to the Network customers and avoid direct assignment.[79] Given the magnitude of the costs, "[t]he economic incentive for wind developers to achieve this end greatly exceeds the incentive to simply avoid the payment of the IM rate."[80] Further, contrary to the testimony of BPA Staff, it is possible that the NOS process would not protect Network customers from excessive costs. Smaller transmission projects could be proposed in place of a single large project or proposed over a series of NOS processes, thereby avoiding direct assignment of the costs to customers requesting the transmission service and causing the costs to be assigned to Network customers.[81] Thus, if the IM rate were to be rolled in, the Network transmission customers would risk bearing in their rates not only the increased costs of the rolled-in Eastern Intertie, but also the potential costs of constructing new facilities and upgrades necessary to transmit additional wind generation. And, to the extent the Administrator considers RN's assertion that BPA could benefit from rolling in the Eastern Intertie by making additional sales (which, as discussed above, is not likely), the Administrator has to consider that those "benefits" are likely to be negated by the costs resulting from RN's proposal.

c. BPA faces substantial new balancing costs.

Under RN's proposal, BPA could be subject to much greater obligations for providing balancing capacity, resulting in increased costs for its customers. Generally, generation interconnected directly with BPA Network transmission facilities is included in BPA's balancing

[79] *Id*. at 7.
[80] *Id*.; *see also id*. at 7-9 (discussing the upgrades to existing facilities that could be necessary to accommodate new wind generation, and the magnitude of those future costs).
[81] *Id*. at 8.

authority area (BAA), which, for a variety of reasons, would be attractive to prospective wind resources.[82] BPA already has a shortage of reserve capacity needed to balance wind and load within its BAA and has been forced to purchase reserves from third-party suppliers, which has been difficult and expensive at times.[83] As the need for balancing capacity increases over time, so will BPA's costs and the risk that those costs will be spread to customers not causing the need.[84]

d. BPA risks establishing a negative precedent and exposing its Network customers to a 12.5 percent rate increase without commensurate benefits.

Adopting RN's proposal could create a precedent for arguments to roll in the Southern Intertie and possibly generation interconnection facilities that are currently directly assigned.[85] According to BPA Staff, "the issue of precedent is important" because roll-in of the Southern Intertie "would increase Network rates by 12.5 percent without commensurate benefits."[86] RN dismisses concerns regarding precedent as hypothetical,[87] but at least one party in this rate case has already submitted testimony questioning the inconsistent treatment of the Eastern Intertie, Southern Intertie, and Northern Intertie that would be created by the decision to roll in the Eastern Intertie.[88]

RN claims that the Eastern Intertie and the Southern Intertie can be factually distinguished.[89] It asserts that the Southern Intertie differs from the Eastern Intertie in that: (1) Southern Intertie connects two areas with sizeable markets, while the Eastern Intertie was

[82] Baker *et al.*, BP-16-E-JP15-01, at 9.
[83] *Id.* at 9.
[84] *Id*.
[85] Baker *et al.*, BP-16-E-JP07-03, at 15.
[86] Metcalf *et al*, BP-16-E-BPA-32, at 12.
[87] Yourkowski, BP-16-E-RN-01, at 13.
[88] *See* Arthur, BP-16-E-MS-03, at 3.
[89] Yourkowski, BP-16-E-RN-01, at 12.

planned and is operated as part of the Northwest transmission grid, (2) the Southern Intertie is heavily utilized, whereas BPA's Eastern Intertie capacity is "stranded," and (3) rolling in the Southern Intertie would have a significant impact on Network rates, while rolling in Eastern Intertie would have a de minimis impact.[90] However, RN's analysis fails to accurately assess the risk.

The bidirectional nature of the Southern Intertie is irrelevant; the Eastern Intertie is likewise capable of transmitting power in both directions. The fact that the Eastern Intertie historically has been used to transmit power primarily in one direction is not determinative. The size of the California market and the frequency of use of the two interties are immaterial. Notably, BPA Staff asserts that "elimination of the IM rate could result in use of BPA's unused Eastern Intertie capacity, whereas BPA's Southern Intertie capacity is fully reserved with pending service requests in the queue."[91] Several parties have testified, however, that this assertion is factually incorrect because "the Southern Intertie capacity in the south-to-north direction is not fully reserved."[92] This arguably likens the Southern Intertie to the Eastern Intertie even more. Finally, the fact that rolling in the Southern Intertie could have a much larger rate impact than rolling in the Eastern Intertie does not contradict the potential similarities between them. If anything, "it simply points out the magnitude of the risk that Renewable Northwest is asking BPA and every Network customer to run for little to no benefit to the region."[93]

The record, as it stands before the Administrator, contains no evidence of the type of distinguishing characteristics between the Southern Intertie and the Eastern Intertie that would

[90] *Id*. at 12-13.
[91] Metcalf *et al.*, BP-16-E-BPA-32, at 12.
[92] Brown *et al.*, BP-16-E-JP12-01, at 3; Arthur, BP-16-E-MS-03, at 5.
[93] Baker *et al.*, BP-16-E-JP07-03, at 17.

allow the Administrator to reasonably conclude that a decision to eliminate the IM rate could not be urged as precedent for the Southern Intertie. Rolling in the Eastern Intertie based on the factors advanced by RN could easily entice Southern Intertie customers to argue for rolling in the Southern Intertie. They could advance any number of arguments that were advanced here to argue that the Southern Intertie and the Eastern Intertie are similar and that rolling them in could promote renewables development. Although those arguments may, and should, ultimately fail, the Administrator should be wary of rolling in the Eastern Intertie based on factors that could undermine the validity of BPA's other segments.

III. CONCLUSION

For the reasons presented above, JP15 respectfully requests that the Administrator reject RN's proposal to eliminate the IM rate, and maintain the Eastern Intertie as a separate segment for ratesetting purposes.

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Post-Hearing Exhibit List of Joint Party 15

Exhibit	Document Title	Date Filed	Status
BP-16-E-JP07-03	Rebuttal Testimony of Joint Party 07	3/16/2015	Admitted
BP-16-E-JP07-03-E01	Errata to Rebuttal Testimony of Joint Party 07	4/6/2015	Admitted
BP-16-E-JP15-01	Surrebuttal Testimony of Joint Party 15	3/30/2015	Admitted
BP-16-E-JP15-01-E01	Errata to Surrebuttal Testimony of Joint Party 15	4/6/2015	Admitted
BP-16-Q-PP-02	Qualification Statement of Nancy Baker	1/14/2015	Admitted
BP-16-Q-PP-03	Qualification Statement of Michael Deen	1/14/2015	Admitted
BP-16-Q-SE-02	Qualification Statement of Eric Espenhorst	3/12/2015	Admitted
BP-16-Q-IN-01	Qualification Statement of Bradley Mullins	2/2/2015	Admitted
BP-16-Q-NR-01	Qualification Statement of Megan Stratman	1/29/2015	Admitted

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing on the Bonneville Power Administration's Office of General Counsel, the Hearing Clerks, and all litigants in this proceeding by uploading it to the BP-16 Rate Case secure website pursuant to BP-16-HOO-02 and BP-16-HOO-05.

DATED: May 1, 2015.

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
BEFORE THE
BONNEVILLE POWER ADMINISTRATION

Fiscal Year 2016-2017 Proposed Power and Transmission Rate Adjustment Proceeding	**)))**	**BPA Docket No. BP-16**

INITIAL BRIEF OF:

PUBLIC POWER COUNCIL

and

POWEREX CORP.

as

JOINT PARTY 06

SUBJECT:

BPA SOUTHERN INTERTIE HOURLY NON-FIRM RATE

May 1, 2015

INITIAL BRIEF OF JOINT PARTY 06

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INITIAL BRIEF OF JOINT PARTY 06

SUBJECT: Southern Intertie Hourly Non-Firm Rate

The Public Power Council ("PPC") and Powerex Corp. ("Powerex"), together designated as Joint Party 06 ("JP06"), jointly file this initial brief regarding BPA's proposed rate for Hourly Non-Firm Service on the Southern Intertie ("IS HNF rate"). As discussed in detail by the JP06 witness panel in their direct testimony (BP-16-E-JP06-01), the IS HNF rate is artificially low and erodes the value of Long-Term Firm transmission rights on the Southern Intertie, to the detriment of the Bonneville Power Administration ("BPA"), its customers and the region. To stop this from happening, and fairly apportion Southern Intertie costs, the IS HNF Rate needs to be adjusted to reflect the level of actual reservations.

I. EXECUTIVE SUMMARY

JP06 urges the Administrator to adjust the rate for HNF service on the Southern Intertie and price it correctly. The current IS HNF rate, which is artificially low and based merely on unfounded "assumptions," undercuts the value of Long-Term Firm ("LTF") service on the Intertie, harms BPA's transmission customers that have invested in IS LTF service, and results in IS HNF customers not paying their fair share of costs. The relief sought by JP06 is an adjustment of the IS HNF rate to reflect actual—not assumed—reservations. BPA would retain the ability to discount the rate, should future circumstances warrant.

The IS HNF issue is the rate aspect of a larger regional problem regarding transfer of transmission value from the Pacific Northwest to California. The root of the problem is that the California Independent System Operator ("California ISO") has designed its market in a manner that grants awards for deliveries into its markets without regard to the seller's transmission priority under BPA's Open Access Transmission Tariff ("OATT") framework. This results in LTF transmission service on the Southern Intertie having no meaningful product quality advantage over HNF service in accessing California markets, despite the priorities of service prescribed in BPA's OATT.

Sellers into the California ISO market are able to rely on IS HNF service at a lower total cost, and avoid paying the higher cost for LTF service, to move energy over the Intertie to California. This ability to leverage non-firm transmission on BPA's system has led to inflated California ISO congestion charges to Pacific Northwest sellers, and effectively expropriates the value of the significant investments that BPA's customers have made in Southern Intertie LTF transmission rights. This has harmed BPA's IS LTF customers, and creates a disincentive for future LTF subscriptions and renewals that, if left unchecked, could ultimately jeopardize BPA's cost recovery for existing and future expansion projects.

The JP06 witnesses submitted testimony based on real-world experience coping with the impact of California ISO market design decisions on BPA's IS LTF service, along with a modest proposal to negate that impact. No BPA transmission customers opposed JP06's proposal, and the Industrial Customers of Northwest Utilities ("ICNU") supported it. Only the BPA Staff supports continuation of the existing IS HNF rate design.

The BPA Staff's position reflects a complacent approach to the issue: LTF service is fully subscribed and there is an existing queue on the Southern Intertie, so there is no basis for concern. The Staff further asserts that it cannot control how the California ISO accepts bids into its market, thereby turning a blind eye to the significant adverse impact of the California ISO market design on the Federal Columbia River Transmission System ("FCRTS"). The Staff's approach is to deny the existence of the problem and push consideration of potential solutions down the road to the next rate case, if then. In Staff's view, action is only necessary if and when BPA itself experiences a disruption to its transmission revenues, notwithstanding the significant harm being experienced by customers that have committed to multi-year investments in IS LTF service.

The Administrator should not accept the Staff's indifference to this important regional issue. In this instance, an unprecedented coalition of BPA's customers have come together to highlight a serious regional problem, which is being aggravated by a BPA rate that perversely creates an economically attractive (and harmful) alternative to LTF service on the Southern Intertie. This problem requires immediate attention to protect BPA's customers and prevent further harm in the future.

The BPA Staff admits that over 50 percent of current Southern Intertie LTF reservations will expire by 2020, and that customers with current LTF reservations generally have no obligation to renew. The Staff also acknowledges that on multiple occasions in the past two years, transmission customers in the queue have declined to contract for LTF service, when offered. Since the start of this year, the volume of requests in the Southern Intertie LTF queue has shrunk by two-thirds. Yet, the Staff maintains its position that no problem exists.

While the consequences of agency inaction are severe, the rate solution proposed by JP06 is modest, and totally within the Administrator's broad discretion over matters of rate design and cost allocation. All that JP06 proposes is to change one factor in the IS HNF rate calculation in order to base the weekly reservations not on the current unfounded assumption of 80 hours per week, but on the average 23 hours per week that BPA IS HNF customers actually reserved during fiscal years 2012 – 2014. This adjustment will have the twin effects of: (1) eliminating the artificial cost advantage that IS HNF service currently enjoys over IS LTF service; and (2) ensuring that all classes of Southern Intertie transmission customers make an equitable contribution toward recovering the fixed costs of the Intertie, consistent with BPA's rate design principles. Basically, JP06 proposes that the Administrator look at actual data and adjust one element of the rate design for the transmission service with the most inferior OATT priority on the Southern Intertie, while retaining the option of discounting this rate should future unforeseen circumstances warrant.

Notwithstanding the Staff's reluctance to recognize or address the issue in this rate period, the Administrator should take immediate action to adjust the IS HNF rate and demonstrate to the region that the benefits of FCRTS service will not be undercut by California ISO market design. Such action will send a clear message that BPA is willing to act decisively to protect its customers and the region from California ISO rules that strip transmission value from BPA and its customers, and that BPA is willing to take necessary steps now to help move the region forward toward broader consensus solutions, such as those brought forward by JP06.

Adjusting the IS HNF rate is the most important and direct step the Administrator can take at this juncture to restore and preserve the benefits of investment in IS LTF service. But the Administrator should not stop there. The Administrator should also initiate parallel processes outside the rate case to explore additional non-rate solutions to Southern Intertie priority of service issues, and the larger erosion of value issue that is plaguing its customers and the region.

II. IDENTITIES AND INTERESTS OF JOINT PARTY 06

Public Power Council's members are preference customers of BPA, all of which purchase network transmission service for delivery of power to their loads and, in many cases, for delivery of their surplus energy to purchasers. Many PPC members purchase intertie transmission services from BPA, subject to the applicable rates, terms and conditions in BPA's OATT and rate schedules. Some of PPC's members are owners of Southern Intertie capacity. Many of PPC's members also purchase energy and power products from non-federal generators located both inside and outside BPA's Balancing Authority Area ("BAA").

Powerex markets power exported from the surplus capability of the predominantly hydropower generation facilities of its parent the British Columbia Hydro and Power Authority ("BC Hydro"). Powerex also markets power from its own portfolio of third-party power purchases. Powerex sells and purchases power throughout the Western Interconnection, including in the California ISO organized markets and with bilateral customers in California. Powerex is one of BPA's largest transmission customers, and has invested in substantial LTF transmission reservations on the Southern Intertie.

III. THE ADMINISTRATOR HAS CLEAR AUTHORITY AND BROAD DISCRETION TO ADJUST THE IS HNF RATE AND PRESERVE THE VALUE OF IS LTF SERVICE

Under the Northwest Power Act ("NWPA") and the Federal Columbia River Transmission System Act ("Transmission Act"), BPA is required to establish rates that meet a variety of requirements. These include setting rates to encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles,[1] and recovering in rates the entirety of BPA's costs of operating, maintaining, and repaying the costs of the capital investments in the transmission system.[2]

BPA treats the Southern Intertie as a segment of its transmission system, and recovers the costs associated with the Southern Intertie facilities in rates specific to users of the Southern Intertie. At issue here is the appropriate recovery of those costs from each of the Southern Intertie transmission service customer classes. BPA has a further obligation to ensure that costs are equitably recovered from federal and non-federal users of the Southern Intertie facilities.[3]

BPA has acknowledged other principles of ratemaking that should guide its rate design decisions, including, among others, the core principle of cost causation.[4] Cost causation is a key equity consideration because it provides that each customer should

[1] Federal Columbia River Transmission System Act § 9, 16 U.S.C. § 838g; Pacific Northwest Electric Power Planning and Conservation Act § 7(a)(1), 16 U.S.C. § 839e(a)(1).

[2] *Id*.

[3] 16 U.S.C. § 839e(a)(2).

[4] *Frederickson et al*., BP-16-E-BPA-14, at 13 (acknowledging that the Administrator has utilized cost causation in rate design); *Tenney et al*., BP-16-E-BPA-16 at 23, 40 (acknowledging cost causation is a factor considered in segmentation).

pay rates sufficient to recover the costs of its uses of the transmission system and not transfer costs to other customers.

The Administrator's discretion is broadest when matters of cost allocation and rate design are involved. Both the United States Court of Appeals for the Ninth Circuit and the Federal Energy Regulatory Commission ("FERC") have held that their authority to review the Administrator's decisions in these contexts is limited.[5] In FERC's case:

> The Commission has previously stated that "the [Northwest Power] Act provided Bonneville with the relatively unfettered discretion to design rates and distinguish among its customer classes in the region within the bounds of the Act." The Commission is not the appropriate forum "in which to challenge any statutory violations . . . relating to issues of rate design."[6]

FERC firmly reiterated this principle in its review of BPA's BP-14 rates, when it rejected a challenge by Powerex to the Administrator's Record of Decision in that proceeding, ruling that challenges to the design of BPA's rates are beyond the scope of the Commission's authority.

In the case of Ninth Circuit review of the Administrator's decision, there is also broad discretion conferred on the Administrator in areas of cost allocation and rate design, but this discretion is tempered by statutory restrictions that the Ninth Circuit is obligated to enforce. BPA is a creature of statute and must strictly adhere to the

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[5] *Bonneville Power Administration*., 147 FERC ¶ 61,053, at PP 9-10 (2014) (approving the BP-14 rates and explaining that FERC's review is appellate in nature and limited to only the three specific requirements of the NWPA); *Aluminum Co. of Am. v. Bonneville Power Admin*., 903 F.2d 585, 590 (9th Cir. 1989) (explaining that, pursuant to the NWPA, the court must affirm electric rates if substantial evidence in the record supports BPA's determination unless the action is arbitrary, capricious, an abuse of discretion, or in excess of statutory authority).

[6] *Bonneville Power Administration*, 100 FERC ¶ 61,102, at P 11 (2002) (footnotes omitted).

confines of its statutes. In this instance, JP06's proposal falls squarely within the discretion afforded the Administrator.

Moreover, the Administrator does not operate in a vacuum. The Administrator is charged by statute with employing sound business practices, and is also charged with understanding the needs of the region.[7] While the BPA Staff is correct in observing that BPA cannot control what the California ISO does, the Administrator certainly has the authority—and the obligation—to manage the FCRTS both proactively and reactively in a manner that is consistent with BPA's statutes and that works for the good of BPA and its customers. Given the present and growing problem of erosion of value of IS LTF service, remedying the defects of the IS HNF rate in this rate case, and considering non-rate solutions outside the rate case process, are totally within the ambit of the Administrator's authority. As an added benefit, these actions are also consistent with ongoing regional collaboration on other important initiatives in which BPA is a key participant.

IV. JP06 HAS PRESENTED COMPELLING AND SUBSTANTIAL EVIDENCE SUPPORTING THE IS HNF RATE ADJUSTMENT

JP06 and ICNU present clear, compelling and substantial evidence that the Administrator should adjust the IS HNF rate in order to remedy its harmful effects.[8]

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[7] 16 U.S.C. § 839g; *see also Bonneville Power Administration*, 20 FERC ¶ 61,292, at p. 61,558 (1982).

[8] On February 4, 2015, JP06 submitted the direct testimony of Ms. Nancy Baker and Mr. Michael Deen of PPC, Mr. Mike MacDougall of Powerex, and Mr. Kevin Wellenius of FTI Consulting, Inc. regarding the IS HNF rate. This testimony appears as BP-16-E-JP06-01.

A. <u>The Current IS HNF Rate Erodes the Value of IS LTF Transmission Rights and Does Not Equitably Contribute To Cost Recovery</u>

The JP06 panel demonstrated the following salient facts regarding the Southern Intertie, the Staff's proposed IS HNF rate, and JP06's proposed rate adjustment:

1. BPA's OATT is intended to resolve congestion on the FCRTS - including the Southern Intertie - according to priority of transmission service: Firm reservations flow ahead of Non-Firm reservations.[9]

2. However, the Southern Intertie is unique in that congestion is *de facto* largely resolved by the California ISO; awards for deliveries to California ISO markets are made without regard to the seller's transmission priority on the FCRTS.[10]

3. In this situation, which does not occur elsewhere on the FCRTS, transmission customers reserving HNF transmission on the Southern Intertie can flow to the California ISO market *ahead of* customers who have reserved LTF service from BPA. Thus, the superior service priority that LTF is supposed to enjoy as a matter of right under BPA's OATT is overridden by the California ISO market design.[11]

4. The potential for this adverse result started with the re-design of California's organized markets in 2009, but has materialized and

[9] *Baker, et al*., BP-16-E-JP06 at 3-4.

[10] *Id*. at 4. *See also Motion by Joint Party 06 to Admit Data Requests and Responses into Evidence*, BP-16-M-JP06-01 at JP06's response to BPA-JP06-25-2 ("*JP06 Evidence Motion*"). The *JP06 Evidence Motion* was granted in the Hearing Officer's April 21, 2015 Order Granting Motions to Admit Data requests and Associated Responses and Attachments into Evidence, BP-16-HOO-21. In the response to BPA-JP06-25-4, BPA Staff confirmed that the majority of the transmission capacity of the southern segments of the COI and PDCI are under the control of the California ISO. *See JP06 Evidence Motion*, BP-16-M-JP06-01 at JP06-BPA-25-4.

[11] *Baker, et al*., BP-16-E-JP06 at 1.

accelerated in the past two years as the California ISO has more actively publicized that its market process ensures that those participants receiving California ISO awards will be able to obtain transmission service on external providers' systems.[12]

5. This situation is aggravated by the fact that the IS HNF rate is artificially low.

   a. The IS HNF rate is calculated based on an "assumption" of expected reservations of 80 hours per week.[13]

   b. This assumption is factually unsupported, and the BPA Staff has admitted that the 80-hour figure is not based on any actual data regarding reservations of IS HNF service.[14]

   c. Based on historical information BPA produced in this case, there were approximately 23 average hours of actual reservations of IS HNF service per customer per week in FY 2012 – 2014.[15]

   d. The BPA Staff's proposal for continued use of an 80-hour per week reservation assumption in calculating the IS HNF rate results in a rate of 3.73 mills/kWh, based on the Staff's proposed annual cost allocation of $15.58/kW.[16]

   e. The Staff's 80-hour per week reservation assumption leads to an inequitable allocation of Southern Intertie costs between HNF and

[12] *Id*. at 19; *see also JP06 Evidence Motion*, BP-16-M-JP06-01 at JP06's response to BPA-JP06-25-2.

[13] *Baker, et al*., BP-16-E-JP06 at 6.

[14] *Id*.; *Linn, et al*., BP16-E-BPA-31 at 3.

[15] *Baker, et al*., BP-16-E-JP06-01 at 7, Attachment A (PX-BPA-25-40).

[16] *Id.* at 14.

LTF customers. If BPA Staff's proposed IS HNF rate is applied to a customer scheduling 1 MW on the Southern Intertie at the actual average level of 23 hours per week, the IS HNF customer would pay a total of $86 per week for service.[17] By contrast, an IS LTF customer scheduling 1 MW of service in the same 23 hours on the Southern Intertie would pay $298 per week for service. This disparity is not only inequitable, but also is contrary to BPA's rate design framework that seeks to set rates that result in similar total weekly contributions to embedded cost recovery across all types of Southern Intertie transmission service.

f. This rate disparity also makes it attractive for a shipper to rely on IS HNF service, purchased only in the specific hours in which service is desired, rather than committing to paying for IS LTF service for every hour of the year in order to access the California ISO market. The lower cost of IS HNF service does not entail higher delivery risk to the shipper because IS LTF service enjoys no product quality advantage under the California ISO market design.[18]

g. Based on the Staff's proposed IS HNF rate, HNF customers would make full and proportionate contributions to embedded cost recovery only if the service is purchased for 80 hours per week –

[17] *Id*. at 9.

[18] *Id*.

which the evidence shows has not been the case in at least the past three fiscal years.[19]

6. If the rate for IS HNF service is instead based on actual average reservations of 23 hours per week, as JP06 is proposing, then the proper hourly rate level for IS HNF service would be 12.97 mills/kW, based on the Staff's proposed annual cost allocation of $15.58/kW and preserving all other aspects of the Staff's calculation.[20]

7. A customer scheduling 1 MW for 23 hours per week at the JP06 proposed IS HNF rate level would pay a total of $298 per week for service, which is in-line and proportionate with what a Southern Intertie customer would pay for LTF service. This is totally appropriate because, as noted above, there is no product quality distinction between the two BPA services under the California ISO's market design.[21]

8. A rate of 12.97 mills/kW for IS HNF service would also be in-line with the tariff rates of three other transmission providers on the Southern segments of the Southern Intertie: Transmission Agency of Northern California ("TANC"); Sacramento Municipal Utility District ("SMUD"); and Los Angeles Department of Water and Power ("LADWP").[22]

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[19] *Id*.

[20] *Id*. at 16.

[21] *Id*. at 9.

[22] *Id*. at 21.

9. Moreover, a rate of 12.97 mills/kW for weekly IS HNF service is less than half of BPA's current estimated cost of $27.48 per MWh for expanding its transmission system.[23]

10. Under the JP06 proposal, BPA would retain its present ability to discount the IS HNF rate – which allows BPA to offer IS HNF service at a lower rate at any time in the FY 2016-2017 rate period if unforeseen circumstances warrant.[24]

11. Potential Southern Intertie transmission customers would also have the ability to acquire unused IS LTF capacity in the secondary market, as an alternative to requesting IS HNF service directly from BPA. This provides further assurance that that the JP06 proposed IS HNF rate will not reduce utilization of the Southern Intertie.[25]

12. JP06 does not object to BPA adopting the same rate for Hourly Firm service on the Southern Intertie, if BPA has a preference for a single IS hourly rate.[26]

13. Since the circumstances of the Southern Intertie are unique, there is no reason or basis for adjusting the HNF rate on the Network or other segments of the FCRTS.[27] As the BPA Staff has admitted: ". . . the rates that Bonneville designs for Southern Intertie service can be made

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[23] *Id*.

[24] *Id*. at 16.

[25] *Id*. at 20.

[26] *Id*. at 22 (noting that IS Hourly Firm service was equal to just one-tenth of the total level of IS HNF service in FY 2012 – 2014).

[27] *Id*. at 22-23.

independently of its determination of rates for service on its other segments of the FCRTS. . . ."[28]

To summarize formulaically what JP06 is proposing in this proceeding, the current formula for calculating the IS HNF rate is as follows, based on 80 hours per week of assumed reservations:

$$\left(\frac{\frac{\$15.58}{\text{kW}}\ \text{(annual cost allocation)}}{\text{8,772 hrs (average \# of hours in FY16, 17}}\right)\left(\frac{168}{\mathbf{80}}\right) = 3.73\ \text{mills/kW}$$

All that JP06 is proposing is to change the formula to reflect 23 hours per week of actual reservations, as follows:

$$\left(\frac{\frac{\$15.58}{\text{kW}}\ \text{(annual cost allocation)}}{\text{8,772 hrs (average \# of hours in FY16, 17}}\right)\left(\frac{168}{\mathbf{23}}\right) = 12.97\ \text{mills/kW}$$

This adjustment will result in a factually supportable rate that achieves equitable cost contribution by all the Southern Intertie users, thereby reducing the incentive for customers bound for the California ISO market to do an end-run around IS LTF service.

B. The JP06 Rate Solution, While Modest in Scope, Will Produce Substantial Benefits to BPA, Transmission Customers, and the Region

While JP06's proposed adjustment to the IS HNF rate calculation is modest, the problem it will help solve is a big one.

Due to factors unique to the Southern Intertie, BPA's artificially low proposed IS HNF rate provides an incentive for transmission customers to avoid committing to IS LTF service, and instead to rely on IS HNF service to deliver energy to the California ISO market with the same effective priority as IS LTF customers. This eliminates the

[28] *JP06 Evidence Motion*, BP-16-M-JP06-01 at BPA Staff response to PX-BPA-25-44 (*caveat* not relevant here has been omitted).

very product quality attributes that BPA's IS LTF customers incurred significant investments in order to obtain, and relied on under BPA's OATT.

Furthermore, incentives that discourage continued investment in IS LTF service undermine the core framework through which BPA recovers the embedded costs of the Southern Intertie facilities. Such incentives also make it less likely that BPA will be able to fund major capital upgrades or expansion of the Southern Intertie facilities from the transmission customers that use the Southern Intertie.[29] These cost recovery pressures are exacerbated by BPA's proposed 15 percent increase in the IS LTF rate at the same time it is instituting a de-rate and major upgrade of the Pacific Direct Current Intertie ("PDCI") line.

BPA recovers the vast majority of the embedded costs of the Southern Intertie facilities from the sale of LTF transmission service.[30] Customers reserving this service pay for it in every hour of the year, whether they actually schedule energy or not.[31] Moreover, customers reserving LTF service often commit to multiple years of this service, in some cases for as long as 20 years. So in addition to recovering the majority of its Southern Intertie costs from the sale of LTF service in each year, BPA derives significant revenue certainty that it will continue to be able to do so for several years into the future.[32] The continued sale of LTF service on the Southern Intertie is therefore vital to BPA's ability to ensure that it continues to be able to fully recover the cost of the Southern Intertie facilities.

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[29] *Id*. at 13.

[30] *Id*. at 10.

[31] *Id*.

[32] *Id*.

In the unique case of the Southern Intertie, transmission customers that have not invested in LTF service may transact with the organized markets in California and deliver power on BPA's Southern Intertie facilities ahead of customers with LTF service reserved pursuant to BPA's OATT. This is due to the California ISO market rules that ensure that transmission service on external providers' systems, including BPA's, will be available to the entities that receive an award from the California ISO, regardless of the entity's actual priority of service on the external providers' systems.[33] This results in BPA transmission customers using the Southern Intertie in a manner that is not determined by the priority of their BPA transmission service, and is thus contrary to BPA's OATT.

Because priority of transmission service on BPA's system is rendered immaterial for transactions with the California ISO, it stands to reason that transmission customers will seek to use the Southern Intertie transmission product that is available from BPA at the lowest total cost. BPA's proposed IS HNF rate thus results in BPA offering an effective (but harmful) alternative to IS LTF service at an artificially low rate. This increases the risk of IS HNF service "cannibalizing" future sales of IS LTF service – and hence raising the prospect of under-recovery of costs.

One purpose of JP06's testimony, in addition to making its proposal, is to raise the awareness of the Administrator to this current, growing, and dangerous situation. The fact that north-to-south service on the Southern Intertie is currently fully subscribed, with a queue for LTF reservation requests, is not a basis to conclude that all is well. The evidence presented in this case demonstrates that BPA's IS LTF transmission

[33] *Id*. at 10. *See also JP06 Evidence Motion*, BP-16-M-JP06-01 at JP06 response to BPA-JP06-25-2.

customers have been experiencing first-hand the harmful effects of California ISO market design on BPA's IS LTF service. And this problem is accelerating as the California ISO more actively publicizes the irrelevance of transmission service priority on adjacent systems when participating in its markets.

BPA faces the following challenges at this time, which will only be exacerbated if the Administrator fails to act in this rate case:

1. Transmission customers with current IS LTF reservations have no obligations to renew service when their reservations expire.
2. Parties with requests in the queue for IS LTF service are generally under no binding obligations to actually commit to IS LTF service if it becomes available.
3. On multiple occasions in the last two years, parties with an IS LTF queue request that were presented with a specific deadline to commit to LTF service declined to do so.

All of these risk factors were confirmed by the BPA Staff in their responses to data requests.[34]

If subscriptions to LTF service on the Southern Intertie decline, there would be several ramifications. First and foremost, the recovery by BPA of embedded costs would be less certain, as a higher fraction of the revenue requirement would need to be recovered from sales of short-term service that may or may not materialize. This

[34] *JP06 Evidence Motion*, BP-16-M-JP06-01 at JP06-BPA-25-2.

increased uncertainty will place increased stress on BPA's financial reserves from year to year.[35]

Second, LTF customers pay for transmission service regardless of whether or not they actually deliver energy in any given hour. This means that customers with LTF reservations have "sunk" transmission costs, and have a financial incentive to fully utilize the Southern Intertie facilities whenever an economic opportunity presents itself.[36] If LTF reservations expire and transmission customers are less willing to commit to additional LTF service, however, then use of the Southern Intertie will increasingly require purchasing short-term transmission service. In that case, transmission costs may no longer be "sunk" at the time that usage decisions are made, and thus there may be a significant number of hours in which variable transmission costs prevent otherwise economic use of the Southern Intertie facilities.[37] In other words, Southern Intertie utilization may decline if a larger portion of the Southern Intertie costs have to be recovered from sales of short-term service.

Third, the loss of LTF sales may simply make it impossible to recover the embedded costs of the Southern Intertie from users of those facilities. While financial reserves may absorb revenue variations from year to year, a chronic failure to recover the revenue requirement from Southern Intertie users will inevitably shift some of the costs of those facilities to BPA's other transmission customers.[38] This would be undesirable and contrary to the cost causation principle of ratemaking, given that power

[35] *Baker, et al*., BP-16-E-JP06 at 12.

[36] *Id*. at 12-13.

[37] *Id*.

[38] *Id*. at 13.

flows on the Southern Intertie are predominantly from North to South (*i.e.*, exports) rather than being used to serve native load in the Northwest.[39]

Finally, if artificially low rates for IS HNF service undermine incentives for transmission customers to invest in IS LTF service, the core mechanism for funding future investments will also be undermined. BPA is currently undertaking a $400 million upgrade to the PDCI, which is proposed to be funded by future additional sales of IS LTF service, and potentially higher rates. Indeed, BPA's current rate proposal already assumes that the entire 120 MW of increased transfer capability resulting from the PDCI upgrade project will be sold to transmission customers as additional IS LTF service.[40] If investment in IS LTF service is perceived to be of diminished value, then BPA's funding assumptions for the PDCI upgrade could prove to be incorrect.

V. THE BPA STAFF'S REBUTTAL CASE IS WHOLLY DEFICIENT AND PUTS THE ADMINISTRATION AT RISK

The BPA Staff denies the existence of the IS HNF rate problem in its rebuttal case, and declares its comfort with the current situation despite the ongoing harm it is causing IS LTF customers. The Staff's testimony is based on two central premises: (1) "BPA has sold all of its long-term firm capacity on the Southern Intertie, and has a lengthy queue of customers waiting for service;"[41] and (2) BPA cannot control how the

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[39] BPA has previously expressed the importance and function of the cost causation principle: "The principle of cost causation in important for fair and non-discriminatory power and transmission rates because, by aligning costs and benefits, it is possible to prevent cost shifts between different customers, send clear price signals for the value of different products, support the equitable allocation of risk, and alleviate concerns that could otherwise limit long-term resource development." 2012 Wholesale Power and Transmission Rate Adjustment Proceeding, Administrator's Final Record of Decision, BP-12-A-02, at 223 (quoting Mainzer *et al.*, BP-12-E-BPA-23, at 21).

[40] *Baker, et al*., BP-16-E-JP06-01 at 13-14, Attachment A (PX-BPA-5).

[41] *Linn, et al*., BP-16-E-BPA-31 at 4. BPA Staff doubled-down in its reliance on the Southern Intertie being fully subscribed in its subsequent responses to data requests. *See JP06 Evidence Motion*, BP-16-M-JP06-01 at JP06-BPA-25-1.

California ISO accepts bids into its own markets.[42] These premises are not well-founded, and do not provide a reasoned or substantial evidentiary basis for the Administrator to maintain the status quo.

The BPA Staff's apparent attitude is that the harm experienced by BPA's Firm transmission customers does not rise to a level for concern unless and until BPA's bottom line is directly impacted. This manifests a callous indifference on the part of the Staff as to whether Firm transmission customers actually receive the quality of service they contracted for with BPA.

A. Fully Subscribed IS LTF Service and an Existing Queue Are Not Sound Bases for Complacency

The Staff's complacency regarding full subscriptions and a long queue is misplaced, and begs the issue of whether a problem has developed with the IS HNF rate that requires the Administrator's attention. As the JP06 witnesses clearly explained in their direct case:

> Uniquely on the Southern Intertie, however, the congestion is largely resolved by the Cal ISO—which grants awards for deliveries in its markets without regard to the seller's transmission priority on BPA's system—and not according to the OATT framework. As a result, BPA transmission customers reserving Non-Firm transmission can flow on BPA's Southern Intertie facilities ahead of customers that have invested in Firm service. This, combined with the IS HNF rate being artificially low, undermines the value of existing Firm transmission rights and creates a disincentive to future investment in Long-Term transmission service.[43]

The Staff has chosen simply to disregard what BPA's customers are experiencing in the field, as they deal with the effects of the California ISO market

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[42] *Linn, et al.*, BP-16-E-BPA-31 at 4.

[43] *Baker, et al.*, BP-16-E-JP06 at 4.

design. The Staff also ignores the potential consequences of this situation for BPA and its IS LTF service offerings. As stated by the JP06 witnesses:

> . . . [T]he availability of IS HNF service at an artificially low rate has numerous adverse consequences. Critically, an artificially low rate for IS HNF service discourages investing in IS Long-Term Firm service, which can lead to reduced utilization, reduced recovery of embedded costs, shifting Southern Intertie costs onto other BPA transmission customers, and creating barriers to major capital investments such as upgrades or expansions of the Southern Intertie facilities. The JP6 proposal ensures that the rate for IS HNF service is not artificially low, and hence, mitigates the risk of all of these adverse outcomes.[44]

Basically, as long as IS LTF service is fully subscribed and a queue for additional service exists, the Staff appears content to deny that there is a problem, and to wait until the next rate case to see if they were right.

The Administrator cannot afford the risk created by the Staff's approach. The Staff has provided no evidence that the present level of reservations and queue requests can be expected to exist in the future. On the contrary, as the Staff admits, over 50 percent of the IS LTF reservations shown on BPA's OASIS are due to expire by 2020, and customers have no obligation to renew service.[45]

Moreover, the strength of the queue can prove illusory. As the Staff further admits, customers with IS LTF requests in the queue generally have no obligation to commit to service if offered, and, in fact, on numerous occasions in the past few years transmission customers with an IS LTF queue request that were presented with a

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[44] *Id.* at 19.

[45] *JP06 Evidence Motion*, BP-16-M-JP06-01 at JP06-BPA-25-2.

specific deadline to commit to IS LTF service declined to do so.[46] The BPA OASIS and IS LTF Pending Queue indicate that since the start of 2015 one customer has already declined to renew IS LTF service, another declined to compete for the same service, and so many requests have abandoned the IS LTF queue that less than one-third of the previously pending total volume remains. There are now no pending queue requests that seek IS LTF service beyond 2018.

Powerex and other customers have multiple IS LTS service agreements that expire next year. Powerex has renewal deadlines approaching as early as May 31, 2015. The BPA Staff's casual assumption that the IS LTF service will remain fully subscribed through the next rate period is a high-stakes gamble that is not supported by the evidence in this case.[47]

B. The Administrator Cannot Afford To Ignore the Impact of California ISO Market Design on the FCRTS

Likewise, the Administrator cannot simply ignore the impact of the California ISO market design on the FCRTS just because BPA does not control what California does. To do so would create the perception that the economic future of BPA's IS LTF customers, BPA's IS LTF transmission revenues, and the fate of regional transmission policies largely rest in the hands of decision makers in California.

The evidence presented by JP06 is uncontroverted regarding the impact of the California ISO market design on BPA's OATT-based priorities of service, and the incentives that the IS HNF rate presents for undercutting IS LTF service in that situation.

[46] *Id*.

[47] The Administrator should also note that on March 17, 2015, Powerex withdrew all of its pending LTF service requests from the Southern Intertie queue, thereby reducing the total volume of pending IS LTF service requests by 3,900 MW.

The Staff failed to address this issue in its testimony, and also declined to address it in responding to JP06's data requests. The Administrator, charged with the obligations of exercising sound business judgment, acting in the best interests of the region, and protecting the FCRTS, does not have the luxury of ignoring external forces encroaching on the value of Southern Intertie LTF transmission.

C. Staff's Remaining Objections to the JP06 Proposal Are Without Merit

The other points raised by the Staff in its rebuttal testimony are without merit.

First, the Staff admits that the 80 hours per week of reservations underlying its IS HNF rate proposal is merely an assumption, and does not dispute the JP06 actual reservation calculation of 23 hours per week, which is based on data supplied and compiled by the BPA Staff itself.[48] But Staff goes on to assert that other transmission providers have non-firm rates that utilize an assumption of 80 hours or more of service to calculate their HNF rates, and appears to draw comfort from following a cookie-cutter approach.[49]

The Staff's comparison is misplaced. BPA confronts a unique problem on the Southern Intertie. Whether other transmission providers have the same problem—undercutting the value of LTF service as a consequence of California ISO market design—and whether or not they have chosen to deal with it, is immaterial. BPA does face this problem, and BPA also has its own organic statutes and related precedent governing the FCRTS. The case law is clear that BPA has broad latitude over issues of cost allocation and rate design, as are presented here, with concomitant deference from the Ninth Circuit and FERC.

48 *Linn, et al.*, BP-16-E-BPA-31 at 3.

49 *Id*.

The Staff also fails to acknowledge that the hourly rates of TANC, SMUD and LADWP cited in Table 1 of its rebuttal testimony are at the levels cited by JP06 in its direct case,[50] which are multiples higher than BPA's current IS HNF rate.

Second, the Staff raises the specter that the JP06 proposal might need to be applied to hourly non-firm rates on the Network, although it admits that it has performed no analysis in that regard.[51] This argument ignores the fact that JP06's proposal is limited to the Southern Intertie. It disregards JP06's uncontroverted evidence that the situation on the Southern Intertie is unique. And, it contradicts Staff's own position that BPA can establish rates for the Southern Intertie independently of the rates it establishes on the Network or any other segment. As the Staff stated in response to PX-BPA-25-44, with one caveat not relevant here:

> The transmission rates associated with the service on the Southern Intertie are based upon the segmented revenue requirements attributed to the Southern Intertie. In addition the rates that Bonneville designs for the Southern Intertie service can be made independently of its determination of rates for service on its other segments of the FCRTS . . . .[52]

Third, the Staff completely ignores JP06's proposal that BPA continue to be allowed to discount the IS HNF rate.[53] The ability to discount can also be used to mitigate any stability concerns regarding future HNF usage and rates raised by the Staff.[54]

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[50] *Baker, et al*., BP-16-E-JP06 at 21.

[51] *Linn, et al*., BP16-E-BPA-31 at 8.

[52] *JP06 Evidence Motion*, BP-16-M-JP06-01 at PX-BPA-25-44.

[53] The Staff did not address discounting in its Rebuttal Testimony, nor would it acknowledge the issue in its responses to JP06's data requests. *See JP06 Evidence Motion*, BP-16-M-JP06-01 at JP06-BPA-25-8.

[54] *Linn, et al*., BP16-E-BPA-31 at 7-8. The Staff declined to quantify the impact of such an IS HNF revenue shortfall on IS LTF rates. *See JP06 Evidence Motion*, BP-16-M-JP06-01 at JP06-BPA-25-6(b).

Fourth, the Staff confuses IS HNF and IS LTF rate comparisons by injecting volumetric and revenue factors.[55] The JP06 proposal is based on actual reservations and is framed on a per-unit basis (mills/kW) that permits a direct apples-to-apples comparison of the two alternative transmission products.

Finally, the Staff attempts to minimize the problem confronted by Southern Intertie LTF customers by asserting offhandedly that ". . . Southern Intertie capacity has uses besides bidding into the California ISO's market, such as bilateral sales."[56] This dismissive approach to a huge Western market illustrates the extent to which the Staff is disconnected from the commercial and economic realities confronting BPA, its customers, and the region.

VI. CONCLUSION: THE ADMINISTRATOR SHOULD ADOPT THE JP06 PROPOSAL

JP06 has presented clear, convincing and substantial evidence of a problem on the Southern Intertie that requires the Administrator's immediate attention. JP06's position is supported by ICNU, and no BPA transmission customer has refuted the evidence presented by JP06. Only the BPA Staff has opposed the JP06 rate proposal, advocating a high-stakes "wait and see" approach while BPA transmission customers continue to bear the consequences of inaction. JP06 has demonstrated that the Staff's opposition to its proposal is baseless and without merit. Thus, the path for action by the Administrator is clear.

Adjusting the artificially low rate for IS HNF service is the single most important measure that can be taken by the Administrator to correct the encroachment of the

[55] *Linn, et al*., BP16-E-BPA-31 at 7.

[56] *Linn, et al*., BP16-E-BPA-31 at 5.

California ISO market design on BPA's OATT framework for FCRTS transmission service, and to ensure that IS HNF customers bear their fair share of embedded costs. This solution is within the scope of the present rate case and the Administrator's full authority and discretion to implement. JP06 urges the Administrator to adjust the IS HNF rate in the Record of Decision.

But correcting the IS HNF rate should not preclude further examination of additional non-rate solutions that are beyond the scope of this rate case. Because of the seriousness of the encroachment issue, and its implications for the region, the Administrator should commit BPA to a process outside of this rate case to explore this problem further and develop additional, complementary non-rate solutions that address priority of service issues on the FCRTS and access to the California ISO market, and may include solutions such as changes to BPA's tariff, business practices, or operations.

WHEREFORE, Joint Party 06 requests that the Administrator issue a Record of Decision in this rate case consistent with the foregoing.

Respectfully submitted,

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May 1, 2015

LIST OF JOINT PARTY 06 EXHIBITS

Exhibit No.	Exhibit Name	Date Filed	Status
BP-16-E-JP06-01	Direct Testimony of Joint Party 06	February 4, 2015	Admitted
BP-16-Q-PP-02	Qualification Statement of Nancy Baker	January 14, 2015	Admitted
BP-16-Q-PP-03	Qualification Statement of Michael Deen	January 14, 2015	Admitted
BP-16-Q-PX-03	Qualification Statement of Michael W. MacDougall	February 4, 2015	Admitted
BP-16-Q-PX-03-E01	Errata to Qualification Statement of Michael W. MacDougall	March 16, 2015	Admitted
BP-16-Q-PX-02	Qualification Statement of P. Kevin Wellenius	February 4, 2015	Admitted
BP-16-M-JP06-01	Motion by Joint Party 06 to Admit Data Requests and Responses Into Evidence	April 17, 2015	Admitted

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document on Bonneville Power Administration's Office of General Counsel and Hearing Clerk and all litigants in this proceeding by uploading the document on the 2016 Joint Power and Transmission Rate Adjustment Proceeding (BP-16) secure website, pursuant to BP-16-HOO-2.

Dated this 1st day of May, 2015 at Seattle, Washington.

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
BEFORE THE
BONNEVILLE POWER ADMINISTRATION

Fiscal Year 2016-2017 Proposed	**)**	**BPA Docket No. BP-16**
Power and Transmission Rate	**)**	
Adjustment Proceeding	**)**	

INITIAL BRIEF OF

Public Power Council
and
Industrial Customers of Northwest Utilities
as

JOINT PARTY 7

May 1, 2015

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I. INTRODUCTION

In accordance with Section 1010.13 of the Bonneville Power Administration's Rules of Procedure Governing Rate Hearings and the Special Rules of Practice adopted for this proceeding (BP-16-HOO-02), the Public Power Council ("PPC") and the Industrial Customers of Northwest Utilities ("ICNU") (jointly, "JP07"), respectfully submit this Brief urging the Administrator to reduce the Bonneville Power Administration's ("BPA") proposed rate increase by incorporating certain, more accurate assumptions regarding the credit for net secondary revenues that should be incorporated into rates, as well as adopting several other adjustments supported by the record. These adjustments will assure that BPA is following its statutory mandate to sell electric power at the lowest possible rates. JP07 also supports BPA Staff's ("Staff") rebuttal testimony regarding Power Risk modeling. Additionally, while recognizing the potential importance of issues raised by Joint Party 04 ("JP04") in its testimony regarding BPA's repayment studies, JP07 argues that the Administrator should direct Staff to make its repayment study transparent and accessible to interested parties for future rate cases, regardless of whether or not adjustments are made in this proceeding. Finally, JP07 addresses the consistent over-forecasting of net transmission interest expense, and demonstrates that an adjustment to Staff's proposal is warranted by the best information available at this time.

This Brief only addresses limited issues, as PPC and ICNU have each submitted a number of other briefs in this proceeding. While JP07 appreciates the efforts made by BPA Staff to reduce the higher pre-rate case estimated power rate increase and to reopen its costs by conducting an Integrated Program Review-2 ("IPR-2") process, the additional measures JP07 proposes will support the health of the regional economy and move BPA's rates toward a sustainable level that would be closer to the prices available in the market.

II. ARGUMENT.

A. In Order to Meet Its Obligation to Sell Power at the Lowest Possible Rates, BPA Should Adjust its Net Secondary Revenue Projections

BPA is charged with providing power to its utility customers and their end-use consumers at the lowest possible rates, consistent with sound business principles. 16 U.S.C. § 838g. The Administrator must set a level for rates that, "in aggregate with all other revenues," will meet BPA's obligations. Id.; 16 U.S.C. § 839e(a)(2)(A). BPA's revenue from off-system sales ("Secondary Revenues") is a major source of 'other revenues' that must be properly credited against BPA's costs if the rates are to be set at the lowest possible level. In this proceeding, $357 million in Secondary Revenues are included in non-slice rates and represents approximately 20% of the revenue requirement allocated to non-slice Tier-1 power rates. BP-16-E-JP07-01 at 7:1-3. Included in the revenue requirement allocated to Power Rates is $14.7 million that has been budgeted for long-term firm transmission on the Southern Intertie, which supports off-system sales that take place outside of the Northwest. Id. at 8:14-18.

In order to properly account for the aggregate of revenues that BPA can expect to receive during the rate period, the Administrator should recognize that Power Services has historically used transmission capacity, for which it collects substantial revenues from power customers, to deliver the approximately 26% of the power sold through off-system sales to southern markets, primarily at the California-Oregon border ("COB") and the Nevada-Oregon border ("NOB"). Id. at 8:2-3. During fiscal year 2014, BPA's sales within the Northwest fetched an average price of $24.97 per MWh, but BPA received an average weighted price of $34.43 for southern sales delivered outside the region. Id. at 8:5-6. This means that during the last rate year, BPA received an average premium of 38% for sales outside the region, as compared to sales within the Northwest, and it made over one-quarter of its sales extraregionally. Id. at 8:23-9:1. Nonetheless, the proposed rates are calculated with the assumption that no sales will be made outside the region because Staff has assigned Mid-Columbia prices to 100% of all off-system sales. Staff offers no support for the proposition that BPA will change its practices and make all sales at Mid-Columbia, and, in fact, admits that each year, "BPA's secondary energy [is] marketed in different volumes and at different points of delivery." BP-16-E-BPA-34 at 2:3-5. As a result, the assumption that BPA will make all of its off-system sales at Mid-Columbia is unsupported by the record, and is inconsistent with BPA's recent practice. Further, the inclusion of $14.7 million in the power revenue requirement would improperly allocate this cost to power customers if BPA does not intend to continue selling power into the more lucrative southern markets.

In order to reflect the aggregate of other revenues that BPA is statutorily required to include in its calculation of rates, the Administrator should increase the net secondary revenues forecast by $25.4 million. To reach this conservative adjustment, JP07 assumed that 24% of net secondary sales will be made at a 38% premium as compared to Mid-Columbia prices. This raw adjustment was then discounted by 20% to reduce the risk of under-collection if variations in market conditions during the BP-16 rate period result in fewer available transactions in extra-regional markets. BP-16-E-JP07-01 at 8:20-9:3.

Staff incorrectly asserts that such an adjustment is not sufficiently reliable because it is based on historical data, and because it is based on only one year of data. BP-16-E-BPA-34 at 2:21-24. Staff's arguments, however, are misplaced. While JP07 was only able to obtain one year of historical data, the 2014 actual data used by JP07 is the best available information reflecting likely off-system sales to southern points of delivery during the rate period. JP07's data provides an accurate representation of BPA's trading practices during the most recent available time period, reflecting market conditions most similar to those that can be anticipated during the rate period. Indeed, when detailed projections cannot be made, it is standard practice throughout the utility industry to use, or begin with, the most recent historical test year because that information will most accurately represent the revenues and costs that can be expected in the rate period. JP07's use of the most recent year's data is not speculative, but represents industry-appropriate sound business principles. The alternative measure, proposed by Staff, is to embrace an assumption that is universally acknowledged to be untrue: that BPA will make all of its off-system sales at Mid-Columbia prices. Indeed, Staff appears to acknowledge that its proposal does not present a fair projection of likely rate-period sales, but rather than trying to enhance JP07's recommendation, it merely states that forecasting sales to COB and NOB is "difficult." BP-16-E-BPA-34 at 2:10-16.

Staff also criticizes JP07 for using only one year of data to develop its proposed adjustment, arguing that one year of data may not produce an accurate projection of BPA's likely off-system sales because a number of variables affect prices during each year. As a threshold issue, the attempt to discredit JP07's use of the most recent annual results ignores the business principles accepted across the utility industry, as discussed above. However, this argument is also disingenuous because JP07 requested multiple years' data from BPA in order to develop a more refined projection, and BPA Staff refused to provide the data on the basis that the request was burdensome. BP-16-E-JP07-01 at Att. A. The Administrator should reject the argument that Staff's proposal should not be adjusted because of Staff's refusal to provide data, particularly when no evidence has been presented to demonstrate that multiple years' results would produce results inconsistent with JP07's conclusions. Further, the data used by JP07 does not rely upon a small number of extraordinary sales which could be influenced by a few outlying data points; rather, JP07 reviewed and incorporated over 49,000 transactions into its analysis and recommendation. BP-16-E-JP07-01 at 8:7-8.

The record in this case presents the Administrator with two options: 1) accept Staff's recommendation, which assumes that BPA will *only* make off-system sales at Mid-C, despite the fact that BPA has budgeted $14.7 million of transmission rights on the Southern Intertie; or 2) accept JP07's adjustment, which would conservatively move BPA's secondary sales revenue toward—but not all the way to—a level representing BPA's most recent, actual market activity. Notably, BPA Staff does not even argue that JP07's recommendation does not represent a more likely pattern of off-system sales; it merely argues that future sales levels are unknown, and in the process, ignores the fundamental principles of ratemaking.

While JP07 would support—and develop—a method for refining off-system sales projections, sound business principles require the use of the best information available. Therefore, the Administrator should adopt JP07's recommendation that the most recent data for off-system sales should replace Staff's assumption that no off-system sales will be made outside of Mid-C, which is a position wholly unsupported by any evidence, and contradicted by Staff's own testimony.

If the Administrator chooses to set rates that assume that all off-system sales will be made at Mid-C, there is no rational basis for requiring power customers to include $14.7 million in transmission purchases in rates. Nowhere in the record does Staff provide an alternate use for such transmission rights. No going concern operating in a rational, businesslike manner would make such an extraordinary purchase of long-term firm transmission rights to another, specific market, if it did not intend to monetize the transmission by making sales of some level greater than zero into that market. Further, the record in this proceeding demonstrates that no reservations of long-term firm transmission are necessary to reach California markets if a specific level of sales cannot be projected because abundant short-term rights are available, and, indeed, flow ahead of many long-term transmission reservations. See BP-16-E-JP06 at 10:17-11:14.

As a result, if the Administrator chooses to assume that all off-system sales will be made at Mid-Columbia, there is no sound business reason to include $14.7 million in firm transmission rights in the power revenue requirement, and these costs should not be charged to power customers. At a minimum, BPA should assume that it will be able to at least recover the $14.7 million through economic secondary energy sales, or re-sale of that transmission capacity.

Given JP07's analysis that BPA achieved $31.8 million in actual value in the most recent historical year, JP07's proposed adjustments are conservative, consistent with sound business principles, and should be adopted by the Administrator.

B. The Administrator Should Direct BPA Staff to Make its Transmission Repayment Study Transparent and Available to the Parties

BPA uses a complex repayment study to determine the level of debt service that will be scheduled for each year during the rate period. Joint Party 04 ("JP04") requested that BPA make two additional runs of its repayment study, proposing two manual adjustments, which had the result of reducing BPA's mandatory debt service in fiscal years 2016 and 2017. BP-16-E-JP07-02 at 10:18-21. Both JP04 and JP07 also called on BPA to make the methodologies and algorithms underlying the repayment study available for review by the parties. Id. at 15:16-22; BP-16-E-JP04-02 at 18:14-15.

In response to the JP04 studies, which demonstrated that changes to the repayment study could result in lower rates than those included in the initial proposal, BPA Staff committed to work "to reduce the repayment levels in the final proposal." BP-16-E-BPA-25 at

7:11-13. While Staff's commitment to work to reduce the repayment levels in the final proposal is welcome and appreciated by customers, the inability of the parties to review the reasonableness of BPA's model or the accuracy of its application in this case is troubling. Indeed, the parties are not even able to state with certainty whether or not a modification such as that proposed by JP04 for BPA's additional study runs would be advisable or practical in the BP-16 proceeding. BP-16-E-JP04-02 at 18:15-16; BP-16-E-JP07-02 at 11:22-12:7.

Staff states a willingness to explore options to make the model accessible. BP-16-E-BPA-25 at 11:22-24. Given the importance of the repayment study, it is imperative that parties be given the opportunity to understand and evaluate this significant component of BPA's rate-setting process. The Administrator should require Staff and interested parties to develop a method that will permit customers to understand and review the repayment study methodologies and their application.

C. The Administrator Should Officially Adopt Staff's Proposal for Power Risk Management in the ROD

Both in BP-14 and BP-16, BPA has maintained that it must retain the option to propose either the inclusion of Planned Net Revenues for Risk ("PNRR"), or modification of Cost Recovery Adjustment Clause ("CRAC") parameters if, between the time of the initial proposal and the final proposal, financial conditions worsen. Administrator's Record of Decision, BP-14-A-03 at 29; BP-16-BPA-33 at 3. If BPA retains the unilateral right to make any changes to PNRR or CRAC proposals at the end of the rate case, customers could be improperly subject to significant rate increases after all procedure has been exhausted. BP-16-E-JP07-01 at 3:13-17.

In order to address this issue, Staff has provided, at JP07's request, a table containing risk mitigation scenarios for fiscal year 2015 revenue changes, and the parties have had the opportunity to comment on the proposed parameters. BP-16-E-BPA-33 at Att. 1. Staff further states that it is willing to include similar information in its initial proposals in future rate cases so that customers will be able to have input regarding the reasonableness of the proposed changes. Id. at 8:11-13.

Staff's table and stated intent to include such information in future initial proposals are very positive steps; nonetheless, Staff refers to the table as illustrative of changes that "could be made" if financial conditions during the rate case worsened. Id. at 8:3-4. Providing a table of risk mitigation changes and providing opportunity for comment on the table would do nothing to remedy the potential lack of due process identified by JP07 if the information is only illustrative. As a result, in order to protect BPA's customers, the Administrator should adopt JP07's proposal that a risk mitigation scenario analysis be included in future initial proposals. Additionally, in this case, the Administrator should follow Staff's recommendation that any changes to the Power Services risk mitigation package from the Initial Proposal should include customer involvement. Id. at 8:20-22.

D. BPA Should Adopt JP07's Adjustment to Net Interest Expense

During the six-year period between 2009 and 2014, BPA consistently over-forecasted the level of net interest expense included in the transmission revenue requirement. BP-16-E-JP07-01 at 12:2-4. During this period, this forecast error has never been lower than $28 million, and it has averaged $34.4 million per year. Id. Unlike the under-forecasting of transmission revenue, which has steadily decreased as BPA has refined its forecasting methodology, the over-forecasting of interest expense has not declined, but has remained steadily between $28 million and $42 million each year. BP-16-E-JP07-01 at 11, Table.

In order to address this consistent, ongoing over-recovery, JP07 recommends that the Administrator reduce the net interest expense forecast by $26.3 million per year, which is equal to only 80% of the historical average error during the past six years, and is a more conservative adjustment than even the smallest observed annual error. BP-16-E-JP07-01 at 12:12-19.

Staff argues that rates were not unnecessarily high during the past six years because these transmission errors were based upon the best information available at the time. BP-16-E-BPA-25 at 1:23-25. While this may be true, ignoring the historical information now available, which demonstrates consistent, significant over-forecasting by Staff, would not be basing the rates upon the best information available today; rather, it would simply perpetuate the errors that have led to inflated transmission rates. Staff acknowledges that "[o]perating revenues and operating expenses vary . . . sometimes in different directions," but nonetheless argues against an adjustment that recognizes the clear and consistent pattern on the basis that multiple factors have contributed to the consistent over-forecasting of transmission expense. Id. at 2:7-3:16, 5:8-9. Sound business principles require that BPA look at the aggregate results of its policies and adjust accordingly; it is not businesslike to ignore the results of operations because those results are driven by individual events that may have unique, though not unexpected, causes. JP07 supports, and has called for the opportunity to participate in the development of refined forecasting modeling before BPA's next rate case, but the Administrator should use the best available data during this rate case, and reduce the net interest expense forecast.

Staff makes the additional argument that because it is proposing a CRAC and Dividend Distribution Clause ("DDC") for transmission rates, the Administrator does not need to refine BPA's approach to net interest forecasts because the CRAC and DDC will act to "address variances" by adjusting rates upward or downward if net financial conditions vary significantly from the rate case forecast. Id. at 5:10-13. This assertion is extremely disturbing in its dismissal of BPA's duty to offer power and transmission at the lowest possible, accurate rates consistent with sound business principles, and in its lack of acknowledgment of the importance to customers of controlling power and transmission costs. As a threshold matter, the Transmission CRAC/DDC is currently only a proposal, and it is opposed by many parties. Further, the CRAC/DDC proposed by Staff in rebuttal testimony would only trigger under extraordinary circumstances. BP-16-E-BPA-30 at 11:13-25. It is not acceptable for BPA to charge higher rates than necessary and then rely upon a true-up to reset rates to the lowest possible level, if, and only if, BPA significantly over-collects its costs. BPA's customers, beset by rising cost pressures and a sluggish rural economy in the Northwest, cannot afford to pay inflated rates, and then have to hope that rates are inflated enough that a DDC will trigger. Further, the CRAC and DDC are risk-mitigation mechanisms. Id. at 1:18-26. Staff proposes a DDC linked to Agency reserve levels and transmission reserves levels, not to actual costs BPA will incur. Id. at 11:15-16. BPA's statutory duty is to consider its costs and revenues in the setting of rates; thus, the Administrator should not adopt Staff's proposal to ignore evidence of over-forecasting and rely on a post-hoc risk mitigation true-up to (possibly) reduce rates to the appropriate level.

III. CONCLUSION

The record in this case demonstrates that in order for BPA to meet its obligation to sell power and transmission at the lowest possible rates consistent with sound business principles, the Administrator should adjust the net secondary revenue projection, require Staff and interested parties to develop a transparent system for reviewing BPA's repayment study methodology, and lower the level of forecast net interest expense for Transmission Services. In addition, the power risk analysis produced by Staff should be recognized and adopted as a meaningful tool in this and future rate cases.

Dated: May 1, 2015

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Post-Hearing Exhibit List of Joint Party 07

Exhibit	Document Title	Date Filed	Status
BP-16-E-JP07-01	Direct Testimony of Joint Party 07	2/4/2015	Admitted
BP-16-E-JP07-01-E01	Errata to Direct Testimony of Joint Party 07	3/12/2015	Admitted
BP-16-E-JP07-02	Rebuttal Testimony of Joint Party 07	3/16/2015	Admitted
BP-16-E-JP07-03	Rebuttal Testimony of Joint Party 07	3/16/2015	Admitted
BP-16-E-JP07-03-E01	Errata to Rebuttal Testimony of Joint Party 07	4/6/2015	Admitted
BP-16-Q-PP-02	Qualification Statement of Nancy Baker	1/14/2015	Admitted
BP-16-Q-PP-03	Qualification Statement of Michael Deen	1/14/2015	Admitted
BP-16-Q-PP-01	Qualification Statement of Kevin O'Meara	1/14/2015	Admitted
BP-16-Q-IN-01	Qualification Statement of Bradley Mullins	2/2/2015	Admitted

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing on the Bonneville Power Administration's Office of General Counsel, the Hearing Clerks, and all litigants in this proceeding by uploading it to the BP-16 Rate Case secure website pursuant to BP-16-HOO-02 and BP-16-HOO-05.

DATED: May 1, 2015

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
BEFORE THE
BONNEVILLE POWER ADMINISTRATION

Fiscal Year 2016-2017 Proposed	**)**	**BPA Docket No. BP-16**
Power and Transmission Rate	**)**	
Adjustment Proceeding	**)**	

INITIAL BRIEF OF:
Public Power Council
Northwest Requirements Utilities
as
JOINT PARTY 9

SUBJECT:
OVERSUPPLY COSTS AND COST ALLOCATION

May 1, 2015

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I. INTRODUCTION AND CURRENT LEGAL FRAMEWORK

In accordance with the applicable rules of procedure,[1] Public Power Council ("PPC") and Northwest Requirements Utilities ("NRU"), jointly referred to as "Joint Party 9" or "JP09," file this Initial Brief to address the issues raised in the testimony of Joint Party 1[2] ("JP01") and Iberdrola Renewables, LLC ("Iberdrola") relating to Bonneville Power Administration's ("BPA") OS-16 Oversupply rate. PPC and NRU are trade associations that represent the common interests of their members. All members of PPC and NRU are preference customers of BPA that purchase requirements power, or transmission services, or both, from BPA under the rates, terms, and conditions set out in their transmission services contracts and BPA's rate schedules.

Following several years of litigation over how BPA manages the oversupply conditions on its system, BPA adopted, and the Federal Energy Regulatory Commission ("FERC" or the "Commission") approved on a final basis,[3] the Oversupply Management Protocol ("OMP"). Under the OMP, "BPA displaces generators located in BPA's balancing authority area under a least-cost displacement cost curve in order to moderate total dissolved gas levels in the Columbia River."[4] The cost curve consists of certain displacement costs submitted by eligible generators, and "BPA displaces generators from the lowest cost to the highest until it achieves the amount of displacement needed."[5] Although the current OMP is effective only through September 30,

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[1] § 1010.13 of the Bonneville Power Administration's Rules of Procedure Governing Rate Hearings (51 Fed. Reg. 7,611 (March 5, 1986)) and the Special Rules of Practice adopted for this proceeding (BP-16-HOO-02).
[2] Joint Party 1 consists of Avista Corporation, PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc.
[3] *Iberdrola Renewables, Inc. v. Bonneville Power Administration*, 149 FERC ¶ 61,044 (2014) ("Order Approving OMP"), *rehearing denied*, 150 FERC ¶ 61,113 (2015) ("Order Denying Rehearing of OMP"); *Bonneville Power Administration*, 149 FERC ¶ 61,043 (2014) ("Order Approving OS Rate"), *rehearing denied*, 150 FERC ¶ 61,112 (2015) ("Order Denying Rehearing of OS Rate").
[4] Bliven *et al.*, BP-16-E-BPA-11, at 2.
[5] *Id.*

2015, BPA Staff testified that "BPA intends to refile the protocol with [FERC] while continuing to work with stakeholders to explore alternative long-term solutions to managing total dissolved gas levels in the Columbia River."[6]

To recover the displacement costs that BPA incurs under the OMP during the FY 2016-2017 rate period, BPA Staff is proposing that the Administrator adopt the OS-16 rate.[7] Any generator in the BPA balancing authority that submits a transmission schedule during the hour of an oversupply event would be subject to the OS-16 rate.[8] "The charge to each generator would be based on that generator's scheduled generation for the hour in proportion to the total amount of scheduled generation in the balancing authority area for the hour."[9] BPA also incurs an administrative cost for the independent evaluator who audits the generators' displacement costs and constructs a least-cost displacement curve.[10] BPA Staff proposes to recover during the BP-16 rate period the administrative costs incurred from FY 2012 through FY 2014 and the forecast costs for FY 2015 through FY 2017. BPA Staff proposes to include the administrative costs in the transmission revenue requirement and allocate them across all transmission segments.[11] The Staff explains that "it is not practical" to allocate the relatively modest (on average, $180,000 per year) administrative costs in the same way as the displacement costs because if there are no oversupply events in a year, BPA would be unable to recover these costs.[12] Thus, "[a]llocating the administrative costs to all transmission rates, and making their recovery independent of oversupply events, ensures that BPA will recover the costs every year."[13]

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[6] Bliven *et al.*, BP-16-E-BPA-11, at 2.
[7] *Id.* at 1.
[8] *Id.* at 2.
[9] *Id.*
[10] *Id.* at 4.
[11] *Id.* at 5.
[12] *Id.* at 4-5.
[13] *Id.* at 5.

The proposed OS-16 rate is substantially similar to the OS-14 rate[14] the Administrator previously adopted after considering a variety of legal parameters governing its establishment.[15] Having asserted jurisdiction under section 211A of the Federal Power Act ("FPA"), FERC approved the OS-14 rate, finding that it, taken together with the OMP, results in "comparable and not unduly discriminatory or preferential transmission service for all of Bonneville's firm transmission customers."[16] Similarly, FERC approved the OS-14 rate under section 7 of the Northwest Power Act ("NWPA"), finding that "the OS-14 rate and the cost allocation embedded in that rate represent an equitable allocation between federal and non-federal use of the transmission system, and that the Administrator has demonstrated that the proposed OS-14 rate is consistent with section 7(a)(2)(A) and (B) of the Northwest Power Act."[17]

How BPA functionalizes and allocates the costs it incurs under the OMP has been the subject of considerable litigation not only before BPA, but also before FERC. Litigation is likely to continue before the Ninth Circuit Court of Appeals.[18] Given this prospect of continued litigation, BPA should adhere strictly to the Congressional mandates set out in its enabling statutes. In establishing rates for the sale and disposition of electric energy and capacity and for the transmission of non-federal power, BPA must ensure that the rates are established in

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[14] Bliven *et al.*, BP-16-E-BPA-11, at 3 (explaining the "limited revisions" BPA Staff made to the OS-16 rate).
[15] Administrator's Final Record of Decision, OS-14 Oversupply Rate Proceeding ("OS-14 ROD"), OS-14-A-02, at 3-5.
[16] Order Approving OMP, 149 FERC ¶ 61,044, at P 43.
[17] Order Approving OS Rate, 149 FERC ¶ 61,043, at P 24.
[18] Iberdrola and some members of JP01, among others, have filed petitions in the Ninth Circuit Court of Appeals seeking review of the OMP that became effective in March of 2012 (*see* consolidated docket 12-71634), the OMP that became effective in March of 2013 (*see* consolidated docket 13-71573), and the OS-14 rate (*see* docket 14-71813). In addition, on April 20, 2015, Caithness Shepherds Flat, LLC filed three more lawsuits challenging BPA's adoption of the OS-14 rate, as well as FERC's orders approving the OS-14 rate under section 7 of the NWPA, and the OMP and the OS-14 rate under section 211A of the FPA (*see* docket numbers 15-71209, 15-71211, 15-71212). PPC and NRU have been, and intend to continue to be, actively involved in the litigation relating to BPA's oversupply management, and hereby expressly reserve their rights to advance any arguments they deem necessary in those proceedings. Nothing contained in this brief shall be construed as a waiver or an intention to waive any arguments or objections already made or that may be made by PPC or NRU in any forum.

accordance with the rate-setting directives in its enabling statutes.[19] In addition, FERC has opined on BPA's methodology for allocating the OMP costs. Because BPA intends to refile the OMP with FERC, BPA would be well-served to ensure the rate it adopts in this proceeding also complies with the general requirements of section 211A of the FPA and the specific directives FERC issued in its orders relating to BPA's management of oversupply.

II. ARGUMENT

JP01 and Iberdrola advance a number of arguments against the OS-16 rate proposed by BPA Staff. Notably, none of those arguments are new, and all were previously rejected by this Administrator. To the extent those arguments were within FERC's purview, FERC also rejected them.

A. Oversupply costs are caused by the interconnection of wind generation that requires compensation for displacement during the oversupply events.

JP01 argues that oversupply costs are caused by "the need for BPA's hydro system to meet BPA's fish and wildlife obligations"[20] and Iberdrola makes a similar argument.[21] As in the OS-14 rate case, JP01 and Iberdrola conflate the cause of oversupply *events* with the cause of the *costs* BPA incurs under the OMP, leading them to advance flawed arguments regarding cost allocation. Analyzing the cause of oversupply *events* does not address the question of how *costs* incurred under the OMP must be allocated. Instead, the "correct analysis of causation of oversupply costs requires that the fact finder look beyond the causes of *events* and look squarely at the cause of *costs* and who benefits from their *incurrence*."[22] And, given the evidence in the

[19] 16 U.S.C. § 839e(a); 16 U.S.C. §§ 838g, 838h.
[20] Holland *et al.*, BP-16-JP01-01-CC01, at 6.
[21] Wrigley *et al.*, BP-16-E-IR-01, at 3
[22] Baker *et al.*, BP-16-JP09-01, at 4 (emphasis in original).

record, that analysis establishes that the "oversupply costs are caused by the interconnection and integration of wind generation."[23]

While BPA's fish and wildlife obligations might be a causal factor of oversupply events, they do not cause BPA to incur displacement costs under the OMP ("OMP costs"). The oversupply conditions are not new to BPA's system, but until the interconnection of wind generation, BPA was able to deal with them by displacing generation within its balancing authority area without incurring any costs. In its testimony, BPA Staff explained that "[b]efore the interconnection and integration of wind generation, BPA would offer generators low-cost or even free power for displacement."[24] "Operators of thermal generation generally accepted these offers, because they saved on fuel costs and their loads were served by BPA's power," and BPA incurred no costs because of oversupply.[25]

The integration of wind generation into BPA's balancing authority area challenged BPA's ability to displace generation without providing incentives beyond low-cost or zero-cost hydropower. Wind generators receive federal and state tax incentives based on the amount of wind energy they generate.[26] Because they do not receive those incentives while being shut down, "they have an incentive to continue operating even when there is an oversupply of energy," and "do not accept BPA's offers of free power."[27] The wind generators' refusal to shut down in exchange for accepting BPA's power is what causes BPA to incur OMP costs:

> Because the wind generators do not voluntarily displace generation in return for free power, BPA must displace and compensate them under the Oversupply

[23] Bliven *et al.*, BP-16-E-BPA-24, at 4; *see also* Baker *et al.*, BP-16-E-JP09-01, at 9 ("Oversupply Management Protocol costs are transmission costs arising out of the interconnection of non-federal generation in the BPA balancing authority are and are caused by the need to compensate renewable generators to cause them to displace their generation during oversupply events.").
[24] Bliven *et al.*, BP-16-E-BPA-24, at 2.
[25] *Id.*
[26] *Id.*
[27] *Id.* at 3.

> Management Protocol. This compensation (in addition to some administrative costs) is the cost that BPA incurs because of oversupply. Therefore, if not for the interconnection of wind generation, BPA would continue to meet its fish and wildlife obligations by displacing generation in its balancing authority area with free Federal hydropower, as it did in the past (and as it still does now with respect to thermal generation), and BPA would not incur any costs for oversupply.[28]

After considering this very evidence in the OS-14 rate case, the Administrator observed that "if wind generators did not exist in BPA's balancing authority area, the situation would be just as it was before the interconnection of wind generation: BPA would not incur oversupply costs."[29] Thus, BPA's pre-existing environmental responsibilities are not the cause of the OMP costs.

B. BPA appropriately functionalized the OMP displacement costs to transmission and allocated them to transmission rates.

Relying on the erroneous premise that OMP costs are caused by BPA's environmental responsibilities, JP01 and Iberdrola argue that they should be functionalized to BPA's power function and allocated to BPA's power rates.[30] Both the Administrator and FERC have rejected this argument, concluding that OMP costs are transmission costs.[31] The Administrator explained in the OS-14 ROD:

> As previously explained, oversupply costs are caused by the interconnection of wind generation in the BPA balancing authority area and by the management of the transmission system to fulfill BPA's environmental responsibilities. Therefore, as a cost of managing the transmission system, oversupply costs are appropriately recovered through transmission rates.[32]

This decision was consistent with BPA's prior characterizations of the OMP as a tool BPA needs to manage its transmission system and ensure reliability. In fact, BPA has specifically stated that

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[28] Bliven *et al.*, BP-16-E-BPA-24, at 3.
[29] OS-14 ROD, OS-14-A-02, at 22.
[30] Holland *et al.*, BP-16-JP01-01-CC01, at 12; Wrigley *et al.*, BP-16-E-IR-01, at 3.
[31] OS-14 ROD, OS-14-A-02, at 26-32; Order Approving OMP, 149 FERC ¶ 61,044, at P 39.
[32] OS-14 ROD, OS-14-A-02, at 30.

"the substitution of hydro power for non-Federal power [under the OMP] is consistent with the day-to-day management of the transmission system," equating it to providing generator and energy imbalance service or redispatching generation in order to relieve a transmission constraint.[33] In this respect, therefore, the OMP costs are just like any other transmission system costs incurred for the benefit of the transmission system and all of its users.

FERC unequivocally affirmed the Administrator's rationale and decision, finding that the OMP costs "are properly allocable to Bonneville's transmission customers."[34] FERC explained:

> Oversupply events affect Bonneville's transmission system by reducing its capacity to handle generation from sources other than Bonneville's hydroelectric power. … Thus, under the OMP, Bonneville incurs costs in order to curtail wind generators during oversupply conditions – a situation that did not exist prior to the interconnection of significant amounts of wind generation on Bonneville's transmission system. Because this interconnection of wind resources to Bonneville's transmission grid is directly related to Bonneville incurring oversupply costs, we find that Bonneville's oversupply costs are properly categorized as transmission costs.[35]

Iberdrola notes in its testimony that it does not agree with FERC's ruling and "is currently seeking clarification and/or rehearing at the Commission on this issue."[36] Since Iberdrola filed its testimony, FERC issued the orders denying Iberdrola's request for rehearing on all counts and affirming its prior finding that BPA properly functionalized the OMP costs to transmission.[37] FERC explained, once again, that BPA's allocation of OMP costs to transmission customers that schedule during oversupply event hours is appropriate because it is those generators "that cause

[33] Request for Leave to Answer and Answer to Intervenor Comments of the Bonneville Power Administration, FERC Docket No. EL11-44-000 (August 15, 2011), at 5.
[34] Order Approving OMP, 149 FERC ¶ 61,044, at P 40.
[35] *Id.* (internal footnote omitted).
[36] Wrigley *et al.*, BP-16-E-IR-01, at 4.
[37] Order Denying Rehearing of OMP, 150 FERC ¶ 61,113, at P 18-19; *see also* Order Denying Rehearing of OS Rate, 150 FERC ¶ 61,112.

Bonneville to need to displace generation and hence create oversupply costs, and thus it is those generators that should be charged oversupply costs."[38]

JP01 argues that FERC's decision was based on a false premise that "'[o]versupply events affect Bonneville's transmission system by reducing its capacity to handle generation,'"[39] given that BPA "conceded in the OS-14 proceeding that oversupply is not caused by insufficient transmission capacity."[40] Iberdrola makes a similar argument.[41] JP01 and Iberdrola misinterpret FERC's statements. "'Capacity' of the system in this context does not mean the presence of available transmission capacity or a reliability concern but rather the overall capability to manage the system without taking action to displace wind generators."[42] FERC made clear on rehearing that it did not base its rulings on a misunderstanding of the availability of transmission capacity: "We recognize that it is not a lack of transmission capacity that causes the need to displace generators, but rather a need to match generation being delivered over the system with load."[43] It reiterated that "[o]versupply costs are nevertheless appropriately viewed as transmission costs because it is generation scheduled to be delivered over the system, ... which is then displaced that creates the oversupply costs."[44]

There is no new evidence in the record of this case that could provide sufficient basis for the Administrator to reverse his prior decision to functionalize the OMP costs to transmission and allocate them to transmission rates.[45] And all the arguments advanced by JP01 and Iberdrola in this case were previously considered and rejected by the Administrator, or FERC, or both.

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[38] Order Denying Rehearing of OMP, 150 FERC ¶ 61,113, at P 19.
[39] Holland *et al.*, BP-16-JP01-01-CC01, at 9.
[40] *Id.* at 8.
[41] Wrigley *et al.*, BP-16-E-IR-01, at 4.
[42] Baker *et al.*, BP16-E-JP09-01, at 9-10.
[43] Order Denying Rehearing of OMP, 150 FERC ¶ 61,113, at P 19 n. 27.
[44] *Id.*
[45] Baker *et al.*, BP-16-E-JP09-01, at 15.

Under the Administrative Procedures Act, any change in policy or practice by BPA must be cogently explained and supported by evidence in the record. In other words, "the agency must examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made."[46] An agency cannot act contrary to the evidence in the record,[47] and, if changing its course, the agency "is obligated to supply a reasoned analysis for the change beyond that which may be required when an agency does not act in the first instance."[48] When BPA departed from its prior decision without the support of substantial evidence and a reasoned analysis, the Court applied this standard to set aside BPA's actions.

1. Section 7(g) of the Northwest Power Act does not address the allocation of transmission costs.

Relying, once again, on the erroneous premise that the OMP costs are caused by BPA's environmental responsibilities, JP01 and Iberdrola argue that under section 7(g) of the NWPA,[49] BPA should allocate the OMP costs entirely to power rates.[50] Section 7(g) provides:

> *Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on December 5, 1980,* <u>or</u> *by other provisions of this section*, the Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this chapter, *all costs* and benefits *not otherwise allocated under this section,* including, but not limited to, conservation, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under section §839d of this title, the cost of credits granted pursuant to section 839d of this title, operating services, and the sale of or inability to sell excess electric power. (Emphasis added.)

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[46] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (internal citation omitted).
[47] *Arizona Cattle Growers' Ass'n v. Salazar*, 606 F.3d 1160, 1164 (9th Cir. 2010).
[48] *Motor Vehicle Mfrs. Ass'n of U.S., Inc.*, 463 U.S. at 42.
[49] 16 U.S.C. § 839e(g).
[50] Holland *et al.*, BP-16-JP01-01-CC01, at 14; Wrigley *et al.*, BP-16-E-IR-01, at 7-8.

As discussed above, the Administrator has previously decided that the OMP costs are transmission costs caused by the integration into BPA's balancing authority area of wind resources that require compensation for displacement, and there is no evidence in this case that could support a reversal of that decision. The Administrator has also rejected the argument that NWPA section 7(g) governs the allocation of these transmission costs.[51]

It is well established that statutes must be construed based on their plain meaning, without adding or eliminating words from the precise language used by Congress, or distorting their meaning.[52] Congress expressly and plainly stated in section 7(g) that certain costs have to be allocated to the power customers, "except to the extent that the allocation of [those] costs … is governed by provisions of law in effect on December 5, 1980 or by other provisions of this section" and those costs are "not otherwise allocated under this section."[53] The costs BPA incurs in providing transmission service at any time, including during oversupply situations, are specifically governed by the provisions of sections 9 and 10 of the Transmission System Act,[54] which was enacted into law on October 18, 1974. Allocation of the transmission costs, including the oversupply costs, is further governed by section 7(a)(1), which expressly provides that BPA's transmission rates "shall be established in accordance with sections 9 and 10 of the [Transmission System Act]."[55] Because allocation of the oversupply costs is expressly governed by sections 9 and 10 of the Transmission System Act and 7(a) of the NWPA, section 7(g) of the NWPA, by its own terms, does not apply to such costs. As the Administrator concluded in the

[51] OS-14 ROD, OS-14-A-02, at 27-32.
[52] *Matter of Borba*, 736 F.2d 1317, 1320 (9th Cir. 1984); *De Soto Securities Co. v. C.I.R.*, 235 F.2d 409, 411 (7th Cir. 1956); *62 Cases, More or Less, Each Containing Six Jars of Jam v. U.S.*, 340 U.S. 593, 596 (1951).
[53] 16 U.S.C. § 839e(g).
[54] 16 U.S.C. §§ 838g (authorizes BPA to set transmission rates to recover all costs attendant to the transmission of power), 838h (requires BPA to ensure that power customers pay power costs and transmission customers pay transmission costs).
[55] 16 U.S.C. § 839e(a)(1).

OS-14 ROD, "oversupply costs are 'costs attendant to the transmission of power' and are allocated under sections 9 and 10 of the Transmission System Act and section 7(a)(1) of the Northwest Power Act rather than under section 7(g)."[56]

Moreover, to allocate to power rates all costs attributable to what BPA and FERC have concluded to be a transmission service issue would result in wholly inequitable allocation: the power rates would be overloaded to the advantage of non-federal transmission customers, who would be getting a "free ride" on BPA's transmission system during oversupply situations. Such an inequitable allocation would violate FERC's directives, sections 9 and 10 of the Transmission System Act, and section 7(a) of the NWPA.

2. Section 7(g) of the Northwest Power Act does not prohibit recovery of fish and wildlife costs through transmission service rates.

JP01 argues that section 7(g) of the Northwest Power Act prohibits BPA from allocating fish and wildlife costs to transmission rates because it requires that all costs of BPA's fish and wildlife measures be allocated to power rates.[57] Again, this argument is based on the inaccurate premise that OMP costs are fish and wildlife costs allocable under section 7(g) of the Northwest Power Act. That aside though, taken to its logical conclusion, this argument would preclude BPA from allocating *any* legitimate costs of providing transmission service on the federal system to transmission rates if those costs are related to fish and wildlife measures. For example, if in the process of constructing a transmission line that crosses a stream or a river, a piling displaces a spawning ground and, as a result, BPA incurs a cost to restore the spawning ground, BPA would be required under section 7(g) to allocate that cost to power rates because, under JP01's interpretation, it would be precluded from allocating it to transmission rates.

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[56] OS-14 ROD, OS-14-A-02, at 30.
[57] Holland *et al.*, BP-16-JP01-01-CC01, at 17.

Indeed, this argument would preclude BPA from allocating to transmission rates not only the appropriate fish and wildlife costs, but also all the other costs listed in 7(g). For example, section 7(g) lists costs of uncontrollable events as the costs to be equitably allocated to power rates. Under the reading of section 7(g) advanced by JP01, this would mean that *all* costs associated with all uncontrollable events, such as the costs of rebuilding transmission lines after an earthquake destroyed them, must be allocated only to power rates. Such an interpretation is nonsensical, contrary to accepted ratemaking principles and the clear language of the statutes governing BPA's ratemaking authority. This is precisely what the BPA Administrators concluded the last few times they rejected this argument.[58] "[S]ection 7(g) does not require that all fish and wildlife costs be allocated to power rates if those costs are caused by the transmission of power."[59]

As a preliminary matter, BPA has long functionalized fish and wildlife costs associated with providing transmission services to transmission and allocated such costs to transmission rates.[60] This is because section 7(g) does not modify the other BPA statutes, like the Transmission System Act, that govern the allocation of BPA's costs and require that the costs of providing transmission service be recovered in transmission rates. As discussed above, the Transmission System Act was a provision of law that was in effect on December 5, 1980, and section 7(g) of the NWPA makes clear that in passing the NWPA, Congress did not intend to

[58] OS-14 ROD, OS-14-A-02, at 29-32; *see also* BP-12 ROD, BP-12-A-02, at 359-65.
[59] OS-14 ROD, OS-14-A-02, at 29 (citation omitted).
[60] BP-12 ROD, BP-12-A-02, at 360 ("BPA has allocated a portion of fish and wildlife costs to balancing reserve capacity based services since 2002."); 363 ("Since the WP-02 rates were established, BPA has continued to include fish and wildlife costs in the embedded cost revenue requirement used to assign costs to the ACS rates. This is consistent with Congress's direction that the costs of providing transmission should be recovered in transmission rates, which include ancillary services costs.").

supersede BPA's ratemaking authority and obligations under other provisions of law.[61] And while Congress added through the NWPA detailed allocation provisions for certain categories of BPA's power costs,[62] the functionalization of fish and wildlife costs was not revised. Indeed, Congress expressly provided in section 7(a)(1) of the NWPA that power and transmission rates shall be established in accordance with sections 9 and 10 of the Transmission System Act. By including the language "[e]xcept to the extent that the allocation of costs and benefits is governed by provisions of law in effect on December 5, 1980" in section 7(g) of the Northwest Power Act, Congress also ensured that section 7(g) did not displace the Transmission System Act.

"Under the Transmission System Act, the Administrator has always had the authority to develop transmission rates to recover the costs associated with maintaining the stability and reliability of the transmission system, which includes allocating costs."[63] Section 9 of the Transmission System Act specifically provides that the Administrator's rates for the sale of all electric power and for the transmission of non-Federal electric power over the Federal transmission system shall be fixed and established having regard to the recovery of the cost of producing and transmitting such electric power.[64] After fully considering this statute, BPA concluded that it "clearly authorizes transmission rates to be set to recover *all costs attendant to*

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[61] OS-14 ROD, OS-14-A-02, at 29 (interpreting the statute in the same manner and citing the same basis for rejecting the argument).
[62] The intent of Congress behind 7(g) of the Northwest Power Act was to make sure that BPA had the authority to recover <u>all</u> the costs of its system and not just those specifically itemized in various statutory provisions. The House Commerce Committee's Section-by-Section analysis of the Northwest Power Act states that section 7(g) "accommodates the need to allocate across all rates those *costs that cannot be allocated to particular rates* to meet the requirement of section 7(a). BPA's obligation and that of the customers is to ensure that all costs are recovered." H.R. Rep No. 96-976, pt. I, at 69 (1979) (emphasis added). Thus, the purpose of 7(g) was not to specifically assign fish and wildlife costs exclusively to power rates, but instead to provide BPA with the statutory authority to recover the costs that were not allocated to particular rates by specific rate directives.
[63] BP-12 ROD, BP-12-A-02, at 361.
[64] 16 U.S.C. § 838g.

the transmission of power."[65] And, the fact that section 7(a)(1) of the Northwest Power Act expressly preserves the mandates of sections 9 and 10 of the Transmission System Act "further underscor[es] congressional intent that costs attendant to the transmission of power be recovered through transmission rates."[66]

As explained above, and as the Administrator previously concluded, "oversupply costs are caused by the interconnection of wind generation in the BPA balancing authority area."[67] "Therefore, as a cost of managing the transmission system, oversupply costs are appropriately recovered through transmission rates."[68] Interpreting section 7(g) to require that these transmission costs be allocated to power rates is contrary to the plain language of section 7(g), the congressional intent, and the Administrator's previous interpretation and application of that statute. Allocating the OMP transmission costs to power rates would also violate sections 9 and 10 of the Transmission System Act, and "would result in a conflict in BPA's statutory mandates."[69] "In addition, Federal users of the system would bear all the costs, even though non-Federal users of the transmission system contribute substantially to the incurrence of oversupply costs,"[70] which would be contrary to the ratemaking principle of cost causation.[71]

Moreover, although FERC has appropriately declined to opine on section 7(g) of the NWPA or otherwise wade into the territory of interpreting BPA's statutes, it expressly "reject[ed] Iberdrola's claim that Bonneville should have allocated the costs at issue to power."[72] FERC approved BPA's allocation of the OMP costs under section 7(a) of the NWPA, stating that

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[65] BP-12 ROD, BP-12-A-02, at 362 (emphasis added).
[66] OS-14 ROD, OS-14-A-02, at 29.
[67] *Id.* at 30.
[68] *Id.*
[69] *Id.*
[70] *Id.*
[71] Baker *et al.*, BP-16-E-JP09-01, at 4-5.
[72] Order Denying Rehearing of OS Rate, 150 FERC ¶ 61,112, at P 19.

it "was satisfied" that BPA's cost allocation methodology "represent[s] an equitable allocation between federal and non-federal use of the transmission system," and that it is also consistent with sections 7(a)(2)(A) and (B) of the Northwest Power Act.[73]

C. BPA appropriately functionalized the OMP administrative costs to transmission and allocated them to transmission rates.

Iberdrola argues that "[t]he administrative costs for OMP should be allocated to power rates" for the same reasons that the OMP displacement costs should be allocated to power rates.[74] The administrative costs "are the fixed costs of oversupply," and indeed, are necessary costs to manage the oversupply events under the OMP. As such, they are transmission costs and must be recovered through transmission rates, just like other transmission costs. In fact, as Iberdrola itself points out, "[t]he administrative costs are a component of the OMP program, and therefore should be allocated in the same manner as the displacement costs."[75] The Administrator should reject Iberdrola's arguments regarding allocation of the administrative costs to power on the same basis as he has rejected Iberdrola's arguments regarding allocation of the OMP displacement costs.

III. CONCLUSION

For the reasons presented above, JP09 respectfully requests that the Administrator reject the arguments advanced by JP01 and Iberdrola.

s/ Irene A. Scruggs	*s/ Betsy Bridge*
Attorney for Public Power Council	Attorney for Northwest Requirements Utilities

[73] Order Denying Rehearing of OS Rate, 150 FERC ¶ 61,112, at P 18.
[74] Wrigley *et al.*, BP-16-E-IR-1, at 11.
[75] *Id.*

Post-Hearing Exhibit List of Joint Party 09

Exhibit	Document Title	Date Filed	Status
BP-16-E-JP09-01	Rebuttal Testimony of Joint Party 09	3/16/15	Admitted
BP-16-Q-PP-02	Qualification Statement of Nancy Baker	1/14/2015	Admitted
BP-16-Q-PP-03	Qualification Statement of Michael Deen	1/14/2015	Admitted
BP-16-Q-NR-01	Qualification Statement of Megan Stratman	1/29/2015	Admitted

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing on the Bonneville Power Administration's Office of General Counsel, the Hearing Clerks, and all litigants in this proceeding by uploading it to the BP-16 Rate Case secure website pursuant to BP-16-HOO-02 and BP-16-HOO-05.

DATED: May 1, 2015.

s/ Irene A. Scruggs

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
BEFORE THE
BONNEVILLE POWER ADMINISTRATION

Fiscal Year 2016-2017 Proposed	)	**BPA Docket No. BP-16**
Power and Transmission Rate	)	
Adjustment Proceeding	)	

INITIAL BRIEF OF:
Public Power Council
Eugene Water and Electric Board
Public Utility District No. 1 of Benton County
Public Utility District No. 1 of Cowlitz County
Public Utility District No. 1 of Franklin County
Public Utility District No. 1 of Snohomish County, Washington
The City of Seattle
as
JOINT PARTY 13

and

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

SUBJECT:
TRANSMISSION RISK

May 1, 2015

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I. INTRODUCTION

In accordance with the applicable rules of procedure,[1] Public Power Council ("PPC") and its members Eugene Water and Electric Board, Public Utility District No. 1 of Benton County, Public Utility District No. 1 of Cowlitz County, Public Utility District No. 1 of Franklin County, Public Utility District No. 1 of Snohomish County, and The City of Seattle, jointly referred to as "Joint Party 13" or "JP13," as well as Industrial Customers of Northwest Utilities ("ICNU"), file this Initial Brief to address the issues raised in the testimony of Bonneville Power Administration ("BPA") relating to transmission risk and use of financial reserves attributed to Transmission Services.

PPC is a non-profit trade organization that represents the common interests of consumer-owned electric utilities in the Pacific Northwest. PPC's members are preference customers of BPA that purchase requirements power, or transmission services, or both, from BPA under the rates, terms, and conditions set out in BPA's rate schedules. ICNU is a non-profit organization whose members are industrial customers in the Northwest, many of which are end-use consumers of BPA power. Therefore, ICNU's members are directly affected by BPA's rates, terms, and conditions of service in a manner similar to BPA's preference customers.

Even though BPA led customers to believe that it would propose no changes to its financial policies, BPA Staff proposed a significant change to the agency's policy on the use of transmission reserves very late in this rate case. This change is unexpected, and ill-considered, and should be rejected. Instead, the Administrator should opt for a more thoughtful approach. Following this rate case, BPA should conduct a broad review of its financial policies in a process that affords all interested parties a meaningful opportunity to participate.

[1] § 1010.13 of the Bonneville Power Administration's Rules of Procedure Governing Rate Hearings (51 Fed. Reg. 7,611 (March 5, 1986)) and the Special Rules of Practice adopted for this proceeding (BP-16-HOO-02).

A. BPA's stated approach to financial risk and mitigation.

In its 1993 rate case, BPA adopted a long-term policy that called for setting rates sufficient for the agency to achieve a 95 percent probability of making its annual payments to the U.S. Treasury in full and on time during each two-year rate period.[2] Beginning in 2002, this standard has been applied separately to BPA's Power Services and Transmission business lines, even though repayment of federal debt is an obligation of the agency as a whole.[3] Thus, in setting rates, BPA conducts independent risk analyses to ensure that both power and transmission rates will be sufficient to meet its Treasury Payment Probability ("TPP") standard.[4] BPA carries out its risk analysis in two distinct steps: a risk assessment step, in which BPA defines operating and non-operating risks, and a risk mitigation step, in which BPA assesses risk mitigation tools for their ability to recover costs in light of identified risks.[5] Among BPA's risk mitigation tools are Financial Reserves Available for Risk (generally, "reserves" or "financial reserves"), Planned Net Revenue for Risk ("PNRR"), Cost Recovery Adjustment Clause ("CRAC"), and Dividend Distribution Clause ("DDC").[6]

BPA Staff testified in the Initial Proposal that in developing the "risk mitigation package" for the BP-16 power rates, it was guided by seven specific policy objectives:

(a) Create a rate design and risk mitigation package that meets BPA financial standards, particularly achieving a 95 percent two-year Treasury Payment Probability.

(b) Produce the lowest possible rates, consistent with sound business principles and statutory obligations, including BPA's long-term responsibility to invest in and maintain the aging infrastructure of the Federal Columbia River Power System (FCRPS).

[2] Transmission Revenue Requirement Study, BP-16-E-BPA-08, at 14.
[3] Power Risk and Market Price Study, BP-16-E-BPA-04, at 2.
[4] Transmission Revenue Requirement Study, BP-16-E-BPA-08, at 14; Power Risk and Market Price Study, BP-16-E-BPA-04, at 1-2.
[5] Power Risk and Market Price Study, BP-16-E-BPA-04, at 1.
[6] *Id.* at 68-76.

(c) Set lower, but adjustable, effective rates rather than higher, more stable rates.

(d) Include in the risk mitigation package only those elements that can be relied upon.

(e) Do not let financial reserve levels build up to unnecessarily high levels.

(f) Allocate costs and risks of products to the rates for those products to the fullest extent possible; in particular, prevent any risks arising from Tier 2 service from imposing costs on Tier 1 or requiring stronger Tier 1 risk mitigation.

(g) Rely prudently on liquidity tools, and create means to replenish them when they are used in order to maintain long-term availability.[7]

The Initial Proposal for the BP-16 transmission rates, however, did not articulate Risk Mitigation Objectives for Transmission nor discuss the efficacy of any such objectives. This was consistent with discussions in BPA's pre-rate case workshops on use of financial reserves for the BP-16 rate period.

B. Customers were led to believe that BPA was not planning to propose changes to its financial policies in the BP-16 rate case.

"BPA conducted workshops on July 16 and August 13, 2014, each followed by public comment periods."[8] "The purpose of those workshops was to consider the potential benefit of developing financial reserves policies to complement the TPP standard, potentially in time for consideration and implementation in the BP-16 rate case."[9] Specifically, Staff explained that BPA "has no policy on reserves level other than the TPP standard," but was "considering developing a policy for determining when reserves are minimally sufficient and when they may be considered robust enough to allow reserves to be used for purposes other than liquidity and risk (e.g., for capital financing, early debt retirement or rate relief)."[10] BPA asked for "stakeholder feedback to help shape the development of a financial reserves policy," and

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[7] Power Risk and Market Price Study, BP-16-E-BPA-04, at 6.
[8] Deen *et al.*, BP-16-E-JP13-01, at 4.
[9] *Id.*
[10] BP-16 Rates Workshop, "Financial Reserves," July 16, 2014, at 15 (available at http://www.bpa.gov/Finance/FinancialPublicProcesses/AccesstoCapital/July_16_2014_Financial_Reserves_Workshop.pdf).

specifically, for comments on the three draft objectives it proposed for a reserves policy framework.[11] "BPA's primary goals in exploring changes to its financial reserve policy appeared to be maintaining its credit rating (and, therefore, more stable costs of non-Federal financing due to a stable credit rating notwithstanding changes in interest rates due to changing market conditions) and development of a more systematic process for determining when financial reserves might be robust enough for uses other than risk mitigation."[12]

Although customers submitted extensive comments in response to BPA's workshops,[13] BPA did not issue a draft financial reserves policy for customers' consideration. In the 2014 Integrated Program Review Final Close-out Report, the Administrator explained: "We also recently held two financial reserves workshops to start discussions with the region about the development of a possible use-of reserves policy. However, we do not anticipate proposing the use of reserves for rate mitigation in the next rate period."[14] BPA did not signal anywhere else that it would propose changes to its financial policies (related to reserves or otherwise) in the BP-16 rate case and did not mention such a proposal in the BP-16 Federal Register Notice.

BPA Staff did not propose changes to BPA's transmission reserve policies in its Initial Proposal.[15] Customers had no reason to believe that BPA would propose any changes to its financial policies for the BP-16 rate period.

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[11] BP-16 Rates Workshop, "Financial Reserves," July 16, 2014, at 16 (available at http://www.bpa.gov/Finance/FinancialPublicProcesses/AccesstoCapital/July_16_2014_Financial_Reserves_Workshop.pdf).

[12] Deen *et al.*, BP-16-E-JP13-01, at 4-5; *see also* BP-16 Rates Workshop, "Financial Reserves," July 16, 2014, at 15 (available at http://www.bpa.gov/Finance/FinancialPublicProcesses/AccesstoCapital/July_16_2014_Financial_Reserves_Workshop.pdf) (identifying one of the three objectives as to "support a strong credit rating").

[13] Deen *et al.*, BP-16-E-JP13-01, at 5.

[14] *Id.* (citing 2014 Integrated Program Review Final Letter and Close-out Report, October 2014, at 2 (available at http://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/2014IPRDocuments/IPR%20Close%20Out%20Document.pdf)).

[15] Deen *et al.*, BP-16-E-JP13-01, at 5.

C. BPA Staff proposed significant changes to BPA's financial policies in its rebuttal testimony.

Even though BPA gave every impression that it would not propose changes to its financial policies, BPA Staff's rebuttal testimony proposed "significant changes to four aspects of its initial proposal," including "the use of transmission reserves."[16] Specifically, BPA Staff proposed to adopt transmission risk mitigation objectives that are "similar" to the risk mitigation objectives used in the Power Services risk mitigation analysis.[17] Among other things, Staff proposed to add a criterion calling for BPA to "[e]nsure robust Agency reserves to help maintain a double-A credit rating."[18] To implement this objective, BPA Staff proposed that the Administrator adopt a CRAC and DDC for the BP-16 transmission rates, linking "the DDC threshold . . . to Agency reserve levels and transmission reserve levels."[19] In other words, Staff proposes that the CRAC and DDC thresholds for transmission rates be "based on the level of Transmission financial reserves necessary to both (1) ensure a 95% [TPP] and (2) maintain overall agency financial reserves at a level BPA perceives to be necessary to support a AA credit rating."[20]

BPA Staff's proposal was apparently responding to some parties' proposals for BPA to use a large amount of transmission reserves to offset costs and mitigate a rate increase through a DDC (and, conversely, implement a CRAC when BPA needs to increase revenue).[21] Staff argued that adding an objective for "Agency reserve levels" is necessary because *if the Administrator adopted the proposals to use transmission reserves to offset transmission rates,*

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[16] BPA's Motion to Amend Procedural Schedule, BP-16-M-BPA-03, at 2.
[17] Deen *et al.*, BP-16-E-JP13-01, at 2; Lovell *et al.*, BP-16-E-BPA-30, at 1.
[18] Lovell *et al.*, BP-16-E-BPA-30, at 3.
[19] *Id.* at 11 (italic emphasis removed).
[20] Deen *et al.*, BP-16-E-JP13-01, at 2-3.
[21] Lovell *et al.*, BP-16-E-BPA-30, at 1, 11.

such a step "would threaten BPA's credit rating."[22] Staff explained that "[c]redit rating agencies view BPA as a single entity," and "care about the total level of BPA's financial reserves, not the level of the reserves BPA attributes to each business unit."[23] A decline in total agency reserve levels could result in a downgrade of BPA's credit rating,[24] which "would result in higher interest expense for the non-Federal debt backed by BPA."[25] This "would affect both business units."[26]

BPA Staff acknowledged that its proposal could have a significant impact on transmission rates during the BP-16 period. While it "do[es] not expect the Transmission CRAC to trigger for either of the years in the rate period," "[t]here is a real chance the DDC could trigger for either or both years, but it depends on both transmission reserves and Agency reserves."[27] If the DDC triggered at its maximum for FY 2016, $100 million would be used to reduce transmission rates, which would reduce the rates by about 11 percent.[28] While Staff's proposed changes to BPA's financial policies are limited to transmission rates, it "plan[s] to propose parallel sets of objectives in the BP-18 rate case" for power rates.[29] Staff claims that while the credit rating support objective for power risk mitigation is important, "it is not so urgent."[30]

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[22] Lovell *et al.*, BP-16-E-BPA-30, at 7.
[23] *Id.* at 4.
[24] *Id.*
[25] *Id.* at 6.
[26] *Id.*
[27] *Id.* at 19.
[28] *Id.*
[29] *Id.* at 9.
[30] *Id.*

D. The Administrator should reject BPA Staff's proposal.

1. BPA should conduct an open and transparent public process designed to allow customers to understand, consider, and discuss with BPA the proposed changes to BPA's financial policies.

BPA's credit rating is important to BPA customers because "there are significant potential cost implications for a credit rating downgrade."[31] The proposal Staff advanced in rebuttal testimony "appears to signal a major change or addition to BPA's financial policy that could have broad-reaching implications for both Power and Transmission Services going forward."[32] Although BPA Staff does not propose to raise rates in this case to support the desirable level of reserves, "the proposed framework opens the door – and arguably sets up a rigid, automatic mechanism – to do so in the future rate cases without due consideration of the costs and benefits of doing so, or of other relevant factors."[33] Given these potential consequences, the Administrator must allow all interested customers to participate in a meaningful way in his evaluation of the Staff's proposal, which is not possible in the rebuttal phase of a rate case.

While providing for surrebuttal testimony may have saved BPA from an outright violation of section 7 of the Northwest Power Act,[34] it did not allow for the transparent public process that a revision of BPA's financial policies warrants. First, the late phase of a rate case, by its nature, restricts the flow of communication between BPA and its customers. This makes it an inappropriate forum for major policy changes. "BPA has historically set and updated its financial policies in an open and transparent public process that considers the full range of

[31] Deen *et al.*, BP-16-E-JP13-01, at 5.
[32] *Id.* at 8.
[33] *Id.*
[34] 16 U.S.C. § 839e(i).

financial challenges facing the agency such as access to capital, financial risk metrics, and cost recovery policies."[35]

Second, only a fraction of BPA's customers are participating in this rate case. There was no prior notice BPA would include proposals for substantive changes to its financial policies. In fact, potential rate case parties had good reason to believe that no such proposal would be contemplated in BP-16: the pre-rate case workshops on the use of BPA's reserves did not produce a proposal, the Administrator clearly told customers that BPA "[did] not anticipate proposing the use of reserves for rate mitigation" in the BP-16 rate period, and the Federal Register Notice did not alert customers to the inclusion of this issue in the scope of this case. "Therefore, customers who potentially would be interested in this issue would have no reason to become parties in this proceeding, absent other reasons for doing so."[36]

Third, those customers who intervened and became parties to this rate case were surprised by the Staff's proposal, given BPA's representations that no changes to its financial policies would be proposed in this rate case.[37] Parties that raised serious concerns with the proposals in the pre-rate case workshops suspended their analyses of the proposals "when Staff represented to parties that these issues would be considered in a stand-alone process prior to BP-18 proceedings."[38] "Given the significant nature of Staff's proposal and its potential broad impacts across the agency, ultimately affecting both power and transmission rates, [the two-week period for filing surrebuttal testimony] is inadequate to allow parties to fully analyze and respond to the new rate proposals offered in rebuttal testimony."[39]

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[35] Deen *et al.*, BP-16-E-JP13-01, at 9.
[36] *Id.*
[37] Saven and Stratman, BP-16-E-NR-04, at 3 ("Frankly, we are surprised by this testimony at this stage of the rate setting process."); Mullins, BP-16-E-IN-03, at 2.
[38] Mullins, BP-16-E-IN-03, at 2.
[39] *Id.*; *see also* Deen *et al.*, BP-16-E-JP13-01, at 9 (stating that "proposing a substantial change to the framework of BPA's financial policy in the middle of a rate proceeding and giving parties just two weeks to respond is not

BPA should not revise its policy on the use of BPA's financial reserves as part of this rate case. Instead of making a decision without adequate facts and without allowing all interested parties to meaningfully participate, the Administrator should opt for a more thoughtful approach. Following this rate case, BPA should conduct a broad review of its financial policies and planning. "This would allow BPA, customers, and stakeholders to engage in careful and transparent review of the full range of financial issue facing the agency as a complete package, including access to capital, capital prioritization, the appropriate level and use of financial reserves and credit rating implications, and develop appropriate policies to address all these elements in appropriate balance."[40]

2. There is no immediate need for the changes proposed by BPA Staff.

"BPA staff offered no evidence of any imminent threat" to its credit ratings, and its excellent credit ratings "were affirmed in 2014 by all three major credit rating agencies (Standard and Poor's, Moody's, and Fitch) with a stable outlook."[41] While some of the credit agencies cited a decline in BPA's financial reserves as a factor in their analysis of BPA's credit worthiness, they also noted the presence of strong factors that temper the effect of reduced reserves.[42] For example, Fitch noted that BPA maintains significant financial flexibility, including the "flexibility to adjust rates through costs adjusters," and Moody's noted "'BPA's plan to maintain sizeable availability under the US Treasury line'" as likely off-setting factors.[43] "The Standard and Poor's Ratings Direct summary actually expressly cited BPA's '[r]obust

appropriate."); Saven and Stratman, BP-16-NR-04, at 6 ("If sufficient time before the rate case began did not exist, two weeks for parties to respond within the rate case is certainly not sufficient for a proposal that could have far reaching impacts throughout the Agency.").

[40] Deen *et al.*, BP-16-E-JP13-01, at 11.

[41] *Id.* at 6. Since JP15 filed its surrebuttal testimony, BPA's credit ratings were affirmed for 2015 by all three credit rating agencies, with a stable outlook. These reports are available on BPA's public website at http://www.bpa.gov/news/Investor/Pages/default.aspx.

[42] Deen *et al.*, BP-16-E-JP13-01, at 6.

[43] *Id.* at 6-7.

liquidity, which tempers the sometimes substantial impacts of variable hydrology conditions on financial performance.'"[44]

Moreover, the level of financial reserves is only one factor in the credit agencies' assessment of BPA's credit worthiness. "Other factors, such as commitment to financial integrity, ability to raise rates quickly in response to a crisis, the value of the underlying assets of the Federal Columbia River Power System (FCRPS), the competitiveness of BPA as a power and transmission service provider, and BPA's overall debt profile, as well as access to capital are significant."[45] As a matter of fact, these factors appear to have outweighed the level of BPA's financial reserves in the credit agencies' past analysis. For instance, Moody's affirmed BPA's Aa1 (equivalent to at least AA level) credit rating in 2014 with a stable outlook even though BPA's financial reserves were below Moody's explicit target range for that credit rating.[46] Similarly, other credit agencies affirmed BPA's credit rating with a stable outlook, referring the strength and adequacy of BPA's liquidity.[47] For example, "BPA has been very successful in maintaining financial liquidity and flexibility to support its current credit rating by increasing power rates in adverse financial and economic conditions, implementing its current financial policies, and reducing the forecast of net secondary revenues thereby reducing the largest source of uncertainty in power revenues."[48]

Thus, there is no evidence in this proceeding to warrant immediate changes as proposed by BPA Staff. Although BPA Staff knew based on comments in the pre-rate case workshops that some parties were interested in pursuing a Transmission DDC, it did not feel compelled to

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[44] Deen *et al.*, BP-16-E-JP13-01, at 7.
[45] *Id.*
[46] *Id.*
[47] *Id.* at 8.
[48] *Id.*

address usage of reserves in the Initial Proposal.[49] Nothing has changed since the Initial Proposal to warrant such a significant change in Staff's approach; in fact, "BPA's finances have been stable or possibly improving since the Initial Proposal."[50] "At the February Quarterly Business Review, BPA provided a forecast of FY 2015 financial performance that indicated Power and Transmission financial reserves higher than those assumed for FY 2015 in the BP-16 Initial Proposal."[51] If the Administrator is concerned that using a large amount of Transmission reserves for rate relief would jeopardize BPA's credit rating, then he should simply reject proposals to do so in favor of Joint Party 7's more modest proposal to use $20 million per year for rate relief for each year of the BP-16 rate period.[52] Regardless, the Administrator should not act without relying on the kind of "substantial evidence" required to support his final rate determinations under the Northwest Power Act.[53]

3. BPA Staff's proposal is piecemeal and would prejudge the outcome of future decisions on BPA's financial policies.

BPA Staff's proposal addresses only one element of BPA's overall financial policy – the use of BPA's financial reserves. Even if it was not too late in the case to raise this issue, it would be imprudent to address one issue of BPA's financial policy in isolation, instead of dealing with the overall financial situation of the agency.[54] All elements of BPA's financial policy are connected and have the potential to affect one another. "Implementing financial policy or objectives on a piecemeal basis, particularly with such limited time for review and

[49] Deen *et al.*, BP-16-E-JP13-01, at 9-10.
[50] *Id.* at 10.
[51] *Id.*
[52] Deen *et al.*, BP-16-E-JP07-02, at 2-9.
[53] 16 U.S.C. § 839f(e)(2) ("The record upon review of such final actions shall be limited to the administrative record compiled in accordance with this chapter. The scope of review of such actions without a hearing or after a hearing shall be governed by section 706 of Title 5, *except that final determinations regarding rates under section 839e of this title shall be supported by substantial evidence in the rulemaking record required by section 839(i) of this title considered as a whole*." (Emphasis added.)); *see also Arizona Cattle Growers' Ass'n v. Salazar*, 606 F.3d 1160, 1164 (9th Cir. 2010) (an agency cannot act on pure speculation or contrary to the evidence).
[54] Deen *et al.*, BP-16-E-JP13-01, at 11.

analysis, is a recipe for unintended and negative consequences both to BPA and to its customers."[55]

Additionally, "[a]lthough BPA staff's proposal in this rate case is for Transmission services, BPA staff also expresses that the proposal would support a 'framework' that would guide future decisions affecting business line and agency reserves."[56] In addition, BPA Staff intends to "propose parallel sets of objectives in the BP-18 rate case" for the Power risk mitigation objectives.[57] Staff intends to make this proposal in the BP-18 rate case even though it plans "to hold workshops before the BP-18 rate case to further discuss and develop parallel objectives with customers."[58] If BPA Staff is determined to make the same proposal in the BP-18 rate case, pre-rate case workshops or another process designed "to discuss and develop" the risk mitigation objectives for Power Services will serve little purpose. "It appears then, that BPA Staff's proposal, if adopted, would substantially prejudge the outcome of future discussions on this important topic without adequate supporting evidence or due consideration of potential consequences or benefits."[59] The fact that BPA can state now that it will make the same proposal for Power Services only demonstrates that Staff's proposal does not give due "consideration to the business-line specific issues and equity principles that are implicated."[60]

III. CONCLUSION

For the reasons presented above, JP13 and ICNU respectfully request that the Administrator reject BPA Staff's proposal to adopt a new set of risk mitigation objectives for

[55] Deen *et al.*, BP-16-E-JP13-01, at 11-12.
[56] *Id.* at 10 (referring to Lovell *et al.*, BP-16-E-BPA-30, at 5 ("This objective supports development of a framework for the DDC and future decisions affecting business line and Agency reserves.")).
[57] Lovell *et al.*, BP-16-E-BPA-30, at 9; *see also* BPA's Data Response NR-BPA-25-24 (Saven and Stratman, BP-16-E-NR-04, Attachment 1, at 5-6.).
[58] Lovell *et al.*, BP-16-E-BPA-30, at 9; *see also* BPA's Data Response NR-BPA-25-24 (Saven and Stratman, BP-16-E-NR-04, Attachment 1, at 6.).
[59] Deen *et al.*, BP-16-E-JP13-01, at 10.
[60] *Id.*

Transmission in this rate case, and instead, conduct a thorough and transparent process before the BP-18 rate case to fully consider all the ramifications of and alternatives to Staff's proposed financial reserves policy and associated rate mechanisms.

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Post-Hearing Exhibit List of Joint Party 13

Exhibit	Document Title	Date Filed	Status
BP-16-E-JP07-02	Rebuttal Testimony of Joint Party 07	3/16/2015	Admitted
BP-16-E-JP13-01	Surrebuttal Testimony of Joint Party 13	3/30/2015	Admitted
BP-16-Q-PP-03	Qualification Statement of Michael Deen	1/14/2015	Admitted
BP-16-Q-PP-01	Qualification Statement of Kevin O'Meara	1/14/2015	Admitted
BP-16-Q-SE-02	Qualification Statement of Eric Espenhorst	3/12/2015	Admitted
BP-16-Q-CO-01	Qualification Statement of Gary Huhta	3/30/15	Admitted
BP-16-Q-SN-03	Qualification Statement of Marie Morrison	3/27/15	Admitted
BP-16-E-IN-03	Surrebuttal Testimony of ICNU	3/30/15	Admitted
BP-16-E-IN-03-AT01	Attachment to Surrebuttal Testimony of ICNU	3/30/15	Admitted
BP-16-Q-IN-01	Qualification Statement of Bradley Mullins	2/2/2015	Admitted

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing on the Bonneville Power Administration's Office of General Counsel, the Hearing Clerks, and all litigants in this proceeding by uploading it to the BP-16 Rate Case secure website pursuant to BP-16-HOO-02 and BP-16-HOO-05.

DATED: May 1, 2015.

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